EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 72

DATE: Tuesday, October 9, 1991

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Wednesday, the 9th day of October, 1991, commencing at 10:00 a.m.

VOLUME 72

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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---Upon commencing at 10:02 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Be seated, please.

THE CHAIRMAN: Mr. Campbell?

MR. B. CAMPBELL: Thank you, Mr. Chairman. I have distributed to those here this morning and have some extra copies which I will put to my right here revised, updated, corrected copies of Exhibits 331A and B, those two tables that were introduced yesterday. So they are now available and as I say have been distributed. Thank you.

THE CHAIRMAN: I should also put on the record, if you are not going to, that you filed another exhibit, 333, entitled, "Materials relating to Environmental and Health Effects of Hydraulic Development, Ontario Hydro, October 1991".

MR. B. CAMPBELL: Yes, that is correct, Mr. Chairman. I think -- anyway, that is correct.

---EXHIBIT NO. 333: Document entitled, "Materials relating to Environmental and Health Effects of Hydraulic Development, Ontario Hydro, October 1991".

THE CHAIRMAN: It has been fairly well circulated, has it, because it will probably be a subject for discussion for tomorrow?

MR. B. CAMPBELL: Yes, I believe, it has

been distributed. My understanding was it was going out at a minimum to all of those who had filed statements of concern for Panel 6.

THE CHAIRMAN: Thank you.

Mr. Passmore, you are here to represent IPPSO at this particular time; is that right?

MR. PASSMORE: Are there going to be questions?

THE CHAIRMAN: Yes, there are.

MR. PASSMORE: To IPPSO?

THE CHAIRMAN: No, to the panel arising out of IPPSO's cross.

MR. PASSMORE: That is fine

THE CHAIRMAN: All right?

MR. PASSMORE: Yes.

KEITH DOUGLAS BROWN,
PAUL FRANK VYROSTKO,
JOHN KENNETH SNELSON; Resumed.

THE CHAIRMAN: Dr. Connell?

DR. CONNELL: Panel, we have spent a lot of time on gas prices, but I have to admit that I still have some difficulties.

I would like, if I may, to refer you to transcript Volume 70, page 12584. Perhaps also to Exhibit 320, page 17, your gas price forecast.

I think this was Mr. Brown, beginning

about line four in the comparison of the gas forecast I used in the 1991 NUG plan and the one that I am planning to use for the 1991 NUG plan; the difference was very slight in the terms of the long-term outlook on gas, which I think is verified by examining that, Exhibit 320, page 17.

And down toward the bottom of the page, beginning at line 19, Mr. Brown, I think you said:

"When I am looking at the year 1995 and the year 2000 and the year 2005, those numbers are very similar. The price that's available today for a proponent in 1991 is a lot less."

And the question:

"So, this change this year, it is just a temporary blip?

And Mr. Brown responded at line 2 on page 12585:

"There is a window of opportunity and it is arguable how long this window is going to be open."

I think I would just like to come to a better understanding of what you were trying to convey, Mr. Brown. Perhaps I could put the question this way: In a contract, there is normally a long-term gas

purchase contract.

Is that often or sometimes a fixed price contract for the full term?

MR. BROWN: All gas contracts are different. They are not normally fixed price; they could have fixed escalation if the developer is that lucky. Normally, the escalation is tied to some other energy parameter or some outlook on gas price.

DR. CONNELL: What would be the most common term then on a gas price contract such as you are describing now? Would it be ten, fifteen, twenty years?

MR. BROWN: Oh, the term of the contract we specify as a minimum is fifteen years.

THE CHAIRMAN: I think you may be talking about two kinds.

Are you talking about the contract between Hydro and the developer?

MR. BROWN: In our contract for a cogenerator it is about typically twenty years to purchase --

THE CHAIRMAN: No, but the contract you are talking about, is it the contract between Hydro and the developer?

MR. BROWN: No, between the developer and

the gas supplier.

THE CHAIRMAN: So why would he be lucky to have an escalation clause?

MR. BROWN: Sorry, lucky to get escalation at electricity, I think was where we ...

THE CHAIRMAN: Oh, I see. All right.

MR. BROWN: Maybe I didn't make myself clear. To have fixed escalation takes a lot of risk out of his fuel costs.

DR. CONNELL: Let's discuss then a fifteen year contract. The provision for escalation that the proponent has with the gas supplier, would there be normally an annual escalation?

MR. BROWN: Yes, that is very typical, and then it is usually spelled out in the contract every year, the escalation rate.

In addition to that, typically every five years, there is a reopener to reflect more market conditions that may not have been captured in the escalation that was agreed at the time the contract was signed. But there are normally caps on high it will go.

In the 1989 plan, information we had received at that time suggested a 15 per cent cap was the highest it could go above the escalation rate

already estimated.

And if you look on Figure 17 from Exhibit 320, you can see in the '89 plan those step changes in the forecast and that was those 15 per cent reopeners every five years. So we assumed the worst case in that forecast.

DR. CONNELL: Yes. Well, perhaps I could ask you then in the light of that description to give me a little more detailed explanation of the text from Volume 70 that I just cited for you, because I think what I am failing to understand is why there is such a window of opportunity now when - and I am going to assume that gas companies and proponents alike were looking at gas price forecasts something like your own, and in any case were making provision for escalation in prices.

So, if there is a depressed price right now, I wouldn't have expected that to have as much impact on the total price of the contract as the text that I cited seems to imply.

MR. BROWN: I think it is important that although it is a depressed market, the gas producers are trying to diversify where they are selling and diversify their markets and they are looking at cogeneration as being a very stable market for their

product rather than being very seasonal. They are willing to take lower prices and lower rates of return under product to get these long-term deals.

I think what we are trying to say, the reason we are getting so much success with cogeneration right now is the contracts they are getting are not as high as the long-term outlook as shown in this forecast and, I believe, also by the NEB, the actual contracts are less than these numbers. And that is really the window of opportunity. Five years from now we don't expect them to be signing those kind of deals, but the gas suppliers are willing to give those contracts right now.

DR. CONNELL: And would it follow that not only are the current prices low, but the provisions for escalation may be less aggressive on the part of the vendors than would otherwise be --

MR. BROWN: That is definitely true. The escalations that we have seen, generally there have been some fixed escalation rates, say, 4 or 5 per cent. There have been other ones that have been tied to the price of electricity, which is then tied to their purchase rate. The gas forecasts that we have here are higher than those numbers.

DR. CONNELL: I wonder, is it reasonable

for us to ask you to document that in some way? For example, could we look at a time series over the last two or three years in which you might plot what I think was referred to as spot prices, and also plot some variable which would reflect perhaps the present value of a fifteen year gas contract or the value of the escalation clauses that are in it? I don't know how that might be done, but ...

MR. BROWN: Definitely I can supply the last year-and-a-half of spot prices. That is very easy to obtain.

DR. CONNELL: That is the easy part, isn't it?

MR. BROWN: Yes.

DR. CONNELL: I would like to see how that gets reflected in the price of gas to proponents.

MR. SNELSON: While that is being discussed, perhaps I could just add something with respect to the degree of consensus on the increase in the real price of natural gas.

[10:14 p.m.]

The forecast prices that we have, considerable increases in the real price of natural gas, is consistent with National Energy Board forecasts and a number of other forecasters, but there is a body

of opinion particularly in the gas industry that prices will not rise that fast, and so I wouldn't like you to work from the assumption that there is uniform, sort of, agreement that the gas price forecast will be as we have indicated.

Our evidence on gas prices primarily will be brought on Panel 8 by a witness from our fuels division.

MR. BROWN: I think what we will try to do is provide an indication of where we can get the information on especially this 1,400 megawatts that we have accepted rate offers and try and get a picture of an aggregate of all of them, showing where they are going and the escalation clauses that are typical.

So we will undertake to do that.

DR. CONNELL: Well, thank you very much. It is an undertaking which is not well defined, Mr. Chairman. Perhaps it needs a number in any case.

THE CHAIRMAN: What's the number?

THE REGISTRAR: 322.16.

---UNDERTAKING NO. 322.16: Ontario Hydro undertakes to provide indication of where information is, especially on the 1,400 megawatts for the accepted rate offers, and to try and get a picture of an aggregate of all others.

DR. CONNELL: I have one other question

following from yesterday's cross-examination, Volume 71. I draw your attention to page 12796. This concerns the small NUGs, the under 5 megawatt group, beginning at line 17, page 12796.

If we looked at the large majority of these projects, those that are under 5 megs are, in fact, paying more than avoided cost.

If you recall, we were paying at 85 per cent of the cost of power, so from that perspective Hydro takes a lot of the risk because we are paying more than we would for the other projects.

If you recall, we were paying at 85 per cent. It is an allusion to evidence at an earlier stage. I wonder if you can recall where that was and lead me to that citation. Was that in direct evidence?

MR. BROWN: I believe our direct was at our purchase rate methodology that is being used today for 1991, and this is a reflection of our purchase rates for 1990 and earlier years.

Before 1991 our purchase rates were based on 85 per cent the cost of power which was higher than avoided cost for those years, and it was our rule, I guess, that we would -- when avoided cost was higher than 85 per cent cost of power we would then go to avoided cost for all projects, and that crossover

happened in 1991.

DR. CONNELL: I see. So the cost of power in this context doesn't mean the system incremental costs?

MR. BROWN: It is the accounting cost of power, which is -- essentially it is the annual energy divided by Ontario Hydro's revenue -- sorry, the inverse of that.

DR. CONNELL: Yes?

MR. SNELSON: I believe there is an interrogatory that gives the history of the non-utility generation rates and the wholesale rates to direct customers, and that number is 5.7.46.

THE REGISTRAR: The last numbers?

MR. SNELSON: 5.7.46.

THE REGISTRAR: 46? Thank you.

THE CHAIRMAN: That will be number...?

THE REGISTRAR: Just let me check to see if that's been...

That will be No. 321.32.

---EXHIBIT NO. 321.32: Interrogatory No. 5.7.46.

DR. CONNELL: Thank you very much. That's all, Mr. Chairman.

THE CHAIRMAN: Mr. Passmore, do you have any questions?

MR. PASSMORE: No, sir, I haven't heard anything alarming.

THE CHAIRMAN: Mr. Rodger?

MR. RODGER: Mr. Chairman, I have one preliminary but important matter I would like to deal with at this time.

I would like to make two letters exhibits to this hearing which I have already provided to Mr. Lucas.

The first is dated August 16, 1991, and it is from myself to Mr. Mattson, who is the counsel for Energy Probe. And the second letter is undated. It is from Energy Probe, and it is entitled "Dear Friend", and it is signed by Mr. Lawrence Solomon, and this letter I only received last week.

Now, these letters, they involve matters before this Board, and with respect to AMPCO, the Energy Probe letter contains various representations about my client, and while this --

THE CHAIRMAN: Just hold on a second. Does Energy Probe know you are going to be raising this issue this morning?

MR. RODGER: Yes, I spoke with Mr. Chapman on Monday about this.

THE CHAIRMAN: Is there anyone here from

Energy Probe? So they know you are going to be raising this this morning?

MR. RODGER: That's right.

As I say, while I don't intend to make submissions on what led up to these letters at this time I will say that ultimately they go to the issue of credibility of Energy Probe, and certainly I will be making submissions on the issue of costs which will take place at the end of the day, but for right now I would just like to get the two letters as part of the record for these proceedings.

THE CHAIRMAN: All right.

THE REGISTRAR: The 16th letter, No. 334.

THE CHAIRMAN: 334? Could we put them in as one exhibit?

MR. RODGER: That would be fine, Mr. Chairman.

THE CHAIRMAN: Both letters go in as one exhibit.

MR. RODGER: I have extra copies for some of the other Intervenors, if they wish.

---EXHIBIT NO. 334: Two letters, the first dated August 16, 1991, from Mr. Rodger to Mr. Mattson; the second letter, undated, from Energy Probe, entitled "Dear Friend", signed by Mr. Lawrence Solomon.

THE CHAIRMAN: I haven't read them. I don't believe either member of the Panel has read them, and so I can't make any comment as to whether they're of any significance or not.

MR. RODGER: Thank you.

THE CHAIRMAN: And we will do nothing about them unless somebody asks us to.

MR. RODGER: That's understood. Thank you.

With that out of the way, with me again is Mr. Don Nevison, and for this Panel I will be asking questions not only on behalf AMPCO but also on behalf the Canadian Nuclear Association.

Now, I also gave Mr. Lucas another package of materials for my cross-examination. Perhaps we can give that an exhibit number, please.

THE REGISTRAR: That will be 335.

---EXHIBIT NO. 335: Package of materials for Mr. Rodger's cross-examination.

CROSS-EXAMINATION BY MR. RODGER:

Q. Panel, I would first like to review the essential underlying principles of Hydro's non-utility generation plan, and as I listened to your evidence in-chief I certainly detected that there is a number of parallels between the underlying principles

of the NUG plan and the underlying principles of the demand management program. So I want to take you through a few of those and see if my understanding is correct.

Would you agree, Mr. Vyrostko, that one of the fundamental assumptions and one of the key principles of the NUG plan is the introduction of approximately 3,100 megawatts of non-utility generation into the Hydro system by the year 2000, and that will in no way adversely affect the quality of electrical service being provided to Hydro customers?

MR. VYROSTKO: A. Our expectation is that those generators will, in fact, provide reliable electricity to the province.

Q. So as the hallmark of the demand management plan was no adverse impact on service, that's also the hallmark of the NUG plan?

A. We expect that there should be no adverse impact.

Q. Would you agree with me that if it became apparent that the quality of service was being adversely affected by non-utility generation then Hydro would go back and re-evaluate its commitments to NUGs?

A. I think that response really looks at or should look at the two elements.

One is the entire program and whether the entire program is contributing to the adverse impact, or whether there are individual either projects or locations that it could be impacting on that reliability, and so therefore we would have to really look at what is causing the reflection in poor reliability and make appropriate decisions based on that.

Q. If you could pin it down to one particular or a series of particular non-utility generators, I take it then you would have a second look at those?

A. We would then be looking at -- with respect to those projects, clearly in the contract that we have with them their reliability would be impacting on their overall revenue stream because if they can't deliver as well as they said they could, they wouldn't be getting the electricity.

What we would then have to do is ensure that in the future any of the inherent problems with that type of project we would try cover off in our negotiations with future projects.

[10:25 a.m.]

Q. Mr. Vyrostko, in your evidence in-chief, you also talked about implementing NUG

projects. And I gather that you stress the importance of having a flexible non-utility generation plan; is that correct?

A. That is correct.

Q. And am I correct when I say that the term flexibility, as you used it, that means that Hydro must be able to efficiently and effectively change the plan and change its course as Hydro's needs change and its customer needs change; is that right?

A. That is correct.

Q. And am I also correct when I say that another fundamental principle of the NUG plan is that Hydro will only incorporate economic NUGs into the system, that is, up to the avoided cost that Hydro would otherwise have to pay to build generation except for the preference premium?

A. If we include the preference premium, it is part of the avoided cost and we would be paying up to that avoided cost.

Q. That's right. Nothing beyond that?

A. Nothing beyond that.

Q. And like in the demand management program where I believe it was Ms. Fraser discussed how Hydro wasn't going to implement uneconomic demand management, it is your evidence that Hydro is also not

going to implement uneconomic NUGs?

A. Our intention is not to implement non-economic NUGs, that is correct.

Q. I think you would agree that certainly that is consistent with your testimony that the ultimate aim for the NUG plan is to do what is in the best interests of the province and the best interests of ratepayers?

A. Yes, along with the interests of the NUG developers as well.

Q. And you have talked a few times about trying to get the best ratepayer benefit as possible; isn't that right?

A. That is correct.

Q. Would you also agree that part of the idea of doing what is best for the province and ratepayers, part of that includes keeping electricity rates under control and, in fact, keeping electricity rates as low as possible?

A. I think it is important that we, in fact, keep our rates as low as possible within the service and the expectation of service that our customers expect from us.

Q. Would you agree that the increases in electricity prices, that has social impacts as well?

A. I would think that increases in electricity rates or increases in a lot of other prices could have social impacts.

Q. Now, if you could leave aside specific contractual arrangements that Hydro may have with a particular non-utility generator, would you agree that as a general principle, that Hydro would not continue to buy electricity from a NUG if it was shown that the arrangement was uneconomic from Ontario Hydro's point of view and, therefore, uneconomic from ratepayers' point of view? Leaving specific contract provisions aside, as a general principle, would you agree with that?

A. If non-utility generation was uneconomic, we would not purchase electricity from a non-economic project.

Q. Okay. Now, you touched upon earlier and I take it from your testimony that there are substantial differences between Ontario Hydro and non-utility generators and not the least of which is the statutory duty imposed on Ontario Hydro to produce power, whereas non-utility generators, they don't have that same statutory duty. Their primary focus is business, is profit; is that a fair characterization?

A. That is correct.

Q. And unlike NUGs, Hydro is duty bound, to supply the province with electricity no matter what happens in the marketplace. And by that I mean, natural gas prices, for example, go through the roof, hydro can't look at that situation and say, well, we are going to lose money by producing this month. Let's start to bear down.

Hydro doesn't have that option, do they?

A. They do not have that option.

Q. And non-utility generators, they may have an option, that option, or that may be a consideration for them; would you agree with that?

A. Well, that is the decision that they have to look at in their overall viability of that project, whether they feel that at any given point in time they are prepared to stop producing for economic reasons.

Q. So you would agree then that that is certainly an option?

A. That is a possibility.

Q. That is a possibility.

And, Mr. Vyrostko, you have testified to that earlier on. You talked about how a certain developer may choose to close down a NUG operation to try and mitigate his losses, I believe, were your

words. And you also said that a developer could change his whole approach to a project and it basically could drop out of the basket because their economic situation changed.

Do you remember giving that testimony?

A. I remember that, yes.

Q. And I also believe you gave testimony that in the U.S., a number of projects didn't materialize even after they were committed.

A. That has happened.

Q. Now, could you tell me how Hydro's customers, who depend on a reliable supply of electricity for their livelihood, how they are safeguarded from those kind of business cycle considerations that may influence the quality and amount of electricity that they produce?

A. I think there's a couple of ways that we try to protect the interests of the ratepayer: One is the inherent value of non-utility generation, in that non-utility generation is made up of a number of smaller projects and, therefore, the impact of any one of those projects on the overall system is minimal. And so through that diversity of supply, it gives you a better overall reliability.

And then secondly is through the way we

structure our contracts, such that the generator is strongly motivated to produce electricity because without producing electricity, the generator would not get paid. And so as long as the generator has invested money into the project and he has made an economic decision to get some return on that, then through our contract, he will, in fact, try to maximize his return through performance.

Q. And does that same rationale apply for the bigger and major supply NUGs, for example, the 350 megawatt project we have heard a little bit about?

A. I think that would apply to virtually all the projects.

Q. Okay. I would suggest to you that these - if we could call them NUG business cycle consideration - this also touches on another theme of the Demand Management Panel, and that is the need for Hydro to understand how decision-makers decide; only in this case, the key decision maker isn't the commercial builder or the residential consumer. It is the independent power producer; would you agree with that?

A. That is one of the members of the industry, that is correct.

Q. Could you tell me how you have incorporated this analysis of determining how

decision-makers decide? How has that been incorporated into this NUG plan?

A. I think the bottom-line factor that is incorporated into the overall plan is the economic element. The economic element from the developer's perspective and ours in that we will only accept economic projects and so, therefore, the developer has to look at what the economics are to make that project happen.

And then secondly, the long-term nature of the business, in that we sign long-term contracts with the developers and, therefore, they use that commitment by Hydro to purchase power from them for many of their decision-making. Financing, for instance, gas supply, that is all predicated on our commitment to buy electricity for the long period of time.

Q. So both those reasons, they really both go to the economics of the situation?

A. The bottom line would be the economics for the developer.

Q. Okay. Now, in the Demand Management Panel and their evidence, there was quite a bit of testimony regarding behavioral and cultural changes that were going to be required to successfully

implement the demand management program.

Now, do you recall reviewing that evidence that your colleagues gave?

A. I have not.

Q. No. Well, in a nutshell, it was discussing how the Province of Ontario, the public, had to view how they consume energy differently and there was talk about how Hydro had to somehow influence how consumers were going to spend their money with respect to energy services, that type of thing.

Would you agree that a behavioral change is also required in terms of successfully implementing the non-utility generation plan and here, the behavioral change is on the part of independent power producers; would you agree with that?

A. I would think that in terms of the behavioral change of what non-utility generation is and its value, I would think the behavioral change is more towards the industrial customers who are the steam users to have them appreciate what value non-utility generation or cogeneration specifically is to them and how that element of the business can, in fact, help them in the industrial sector and then have an overall economic benefit to the province as well.

Q. So you don't see behavioral change

being applicable to independent power producers?

A. Well, I think many of the independent power producers are entering the business knowing what the fundamental rationale is for that business. And so, therefore, they are entering it on that aspect.

Q. That, again, is back to strictly economic criteria, correct?

A. Well, it is not strictly economic criteria. The economic criteria is the key bottom line for the developer.

But again, going back to the long-term element of the contract, they clearly have to bring forward a project that is going to last for the twenty years to then give them the economic. So, although the economics is the bottom line, the technical viability of the project is there as well.

Q. So, what is the other criteria? We have economics and technical criteria.

Are there any other factors involved in this process?

A. I think the other element that is there with the proponents, anybody building a facility, is the impact that those facilities have on the local situation, whether it is the social impacts, whether it is the environmental impacts.

And, therefore, any of the private developers coming in looking at projects, they really have to be aware of the process that is required for them to get the approval of their project.

Q. So that is also very important, those other aspects, those social, environmental aspects?

A. That is all part of their whole understanding of the business and what it takes to put a project together.

Q. I wonder if you could turn to page 1, please, of my Exhibit 335. And this is one page from the Ontario Hydro Chairman's speech to the IPPSO conference and trade show recently.

If you go to the third paragraph from the bottom of that page, it reads:

> Not only will there be changes in your relationship with Hydro, but you will have to start thinking of yourselves as much more than suppliers; like Hydro, you will have to start seeing yourselves in the context of the people who will be using your electricity. You are going to be far more than wholesalers to Hydro.

And the next paragraph:

> Whether you like it or not - which to

me implies some kind of change is needed - you now have to deal with this issue such as environmental assessment, community relations and in some cases, aboriginal relations. It is up to all of us to earn public acceptance of the ways we generate electricity and of the sites selected to do it.

Would you agree, Mr. Vyrostko, that this quote, it pertains to what you were just talking about, about social and perhaps other environmental considerations?

A. I believe it is doing that, yes.

[10:40 a.m.]

Q. Would you also agree with me that perhaps a behavioural change that is needed, at least the chairman thinks it's needed, is that independent power producers are going to have see themselves as not just selling a product but there is a higher duty or a higher responsibility with respect to providing electricity to the province?

Do you agree that that would be a fair interpretation of this?

A. Well, that is the chairman's interpretation. That is correct.

Q. And if we could go to the fourth paragraph from the top of that page:

As you become a more important part of the overall system Hydro will expect greater reliability of supply from you. With non-utility generation contracts running as long as fifty years we must be able to count on you. We would like to see you record and publish your reliability performance as we do.

I wonder, first of all, Mr. Vyrostko, could you explain this recording and publishing of reliability performance? What did the chairman mean by this?

A. I believe Mr. Brown discussed that in his direct evidence with regard to a program and an activity that we have on monitoring of non-utility generators, and because performance data is not extensive to date, both in the United States and in Canada on reliability, we are undertaking a program to in fact start to collect this information from all larger non-utility generators.

Q. So when the chairman says 'we would like to see independent power producers record and publish their reliability performance', I take it that

just isn't done at present?

A. There is a little bit of that. We have started this in the past year. There is a little bit of that information coming forward to us, and I believe what he is asking for is the cooperation from all non-utility generators to provide that information.

Q. And certainly, this would be important to get this information, I take it?

A. I think it would be important for us, yes.

Q. Would you agree, Mr. Vyrostko, that if this Board finds favour with Hydro's non-utility generation plan then that approval should include the Board recommendation that NUGs in fact be required to record and publish their reliability performance?

MR. B. CAMPBELL: I am not prepared, Mr. Chairman, to have the witnesses state a position on Ontario Hydro's behalf with respect to any particular terms and conditions. I believe that is the role of Hydro's counsel, and I do raise a question as to whether the Board has jurisdiction to impose any terms and conditions on parties to this hearing other than Ontario Hydro.

THE CHAIRMAN: Well, let's keep it off terms and conditions of the Board, but let's keep it on

what Hydro would like to see done from its own point of view. I take it they would like more information than they are now getting and they would like to have the cooperation of the industry.

If you want to continue that line and be more specific, that would be all right.

MR. RODGER: I think Mr. Vyrostko agreed it would be important to get this information, and I am content to leave it at that.

THE CHAIRMAN: All right.

MR. RODGER: Q. Would you agree, Mr. Vyrostko, that this idea of recording and publishing reliability performance, this also goes to the importance of a reliable electricity supply for the province and it also goes to this idea of a more broader societal obligation on behalf of independent power producers to in fact supply a reliable supply of electricity?

MR. VYROSTKO: A. That's correct. That's one of the reasons why they are in the business, is to provide that, so we would like to know how well they are doing.

Q. Now, you may have said it in your direct testimony, but how long have you been involved with dealing with non-utility generators?

A. Three years.

Q. Three years? In that time period have you seen evidence of these types of changes where independent power producers are moving towards a more broader role in terms of their services and the products they are providing to the province?

A. I believe so.

Q. And could you give us some examples of those, or specifics?

A. I think one of the areas where we have seen a movement towards the recognition that the non-utility generation industry is an industry that's here to provide electricity and electricity over the long term is what we call a third party developer.

Q. Sorry, the third party...?

A. Third party developer. In essence, it is the entrepreneur who in many cases is dealing with steam hosts, the industrial plants, and is in fact using the steam from the plant to then produce electricity, getting into a long-term contract with the steam host and selling electricity to Hydro.

The reason why I say it's reflected in this long-term commitment is in fact because that third party developer is approaching a business as a longer-term business. He's approaching it as what I

would call a quasi-utility; in essence, one who has a recognition of their need to provide electricity over the long term, and that in fact they are signing a contract both for steam and for electricity in the long term.

With a number of these types of third party developers we are starting to see that, in fact, the industry has that commitment.

Q. So you are seeing evidence that the companies that are getting involved in this process, it is your perception that they are in it for the long term?

A. Yes.

Q. I had one question of clarification. I believe it was Mr. Vyrostko, when you talked about the initial request for proposals, and you said that it was your impression that in some of those proposals they didn't really fully understand what they were getting into or didn't fully understand the economics of the situation.

I wonder if could you just expand upon that. I didn't understand that.

A. Well, basically before we had a request for proposal and we didn't have many of the needs that we were looking for from project developers

identified. We had an open door policy, and in that process people were coming forward with in some cases almost ideas and saying, look, I am interested in the proposal, a project, and I would like to know how to go about doing it.

What their request for proposal did, it put forward the minimum information that was necessary for a project to be identified to the extent that we can then starting looking at it in terms of how it fits into the system. What it did, is it identified a number of factors that are necessary for a proponent to look at before they can really come and talk to us in a serious way and start to negotiate.

Q. So part of the problem was that some of them were just strictly ideas and they hadn't followed through all the analysis then in terms of financing, in terms of the long-term commitment, and so forth?

A. I think if we put it into perspective, back when we were looking at the request for proposal, this was just after I came. In fact, it was even being looked at before I came, which was in sort of '88.

The business was very new then. There were not that many people in the industry. One of our

objectives was to in fact help to establish the industry and help to establish a common framework for information and assessment, and so that was just a reflection of the infancy of the industry, and we saw that as being an important need.

Q. At that time, other than combustion units and Hydro units, did you get alternative energy forms in that first request for proposals - solar energy, wind power, this type of thing?

A. We did -- we did not get any of the solar or wind, and the predominant reason why we didn't is the request for proposal was for projects above 5 megawatts.

Q. I see.

A. So, typically those projects would not be that large.

Q. I have a few questions with respect to transmission.

In his speech that I referred to earlier, the chairman's speech, he stated that Hydro has budgeted over $800 million for a transmission system upgrade.

I know we have heard about this in Panel 2 as well. Mr. Snelson, I believe it was your testimony when you talked about integrating NUGs into

the Hydro system. You stated that:

Hydro had to pay more attention to encouraging non-utility generation in the right locations and in locations that will reduce transmission requirements rather than increase transmission requirements.

Do you recall that testimony?

MR. SNELSON: A. Yes, I do.

Q. Would it be a fair characterization of your testimony with respect to transmission that at present there is a considerable amount of uncertainty with respect to transmission limitations in the province and where NUGs can and cannot be located?

A. Clearly, there is uncertainty, but I believe the thrust of my evidence was that in the long term the transmission system can be adjusted to accommodate non-utility generation wherever it locates, and that in the 1990s because of long transmission approval times, in addition to the construction times, that the flexibility to adjust the transmission system to accommodate is limited.

Q. And I believe the lead time for transmission was six to ten years; is that fair?

A. I believe the figures I used were

five to ten years.

Q. Five to ten years?

A. That's not significantly different.

Q. Can you tell me, Mr. Snelson, in screening NUG proposals to date has Hydro been forced to reject sound NUG proposals because of transmission limitations?

MR. VYROSTKO: A. Yes, we have.

Q. Can you give me the locations of those?

A. I can say that they have been in the northeastern region.

Q. Is that the only Hydro region?

A. Northwestern region as well.

Q. So those are the only two?

A. I believe where we have actually turned down proposals -- there may be -- we may have also turned down a proposal in the western region as well.

Q. It was restricted to those three regions?

A. I believe so.

Q. How about downsizing of a NUG proposal because of transmission limits? And by this I mean you get in a proposal that would otherwise be

viable for 150 megawatts and you turn it around and say we can't take 150 but we can take 5?

A. I think that through the evidence that I have put forward so far we talk about optimizing of projects and looking at the necessary size of project in some cases to make it happen.

Yes, we have downsized projects to allow them to fit into the system.

Q. And this downsizing, this was for transmission issues specifically, was it?

A. There has been some downsizing for transmission issues.

THE CHAIRMAN: Could you just remind me of how many regions there are? I have forgotten.

MR. VYROSTKO: There are 5 wholesale regions.

THE CHAIRMAN: And so 3 out of the 5 you rejected NUGs for transmission reasons; is that right?

MR. VYROSTKO: That's correct.

MR. RODGER: Q. Can you tell me, has there been any constraints around the Napanee area, Belleville and Kingston area?

THE CHAIRMAN: Isn't that getting a little site specific?

[10:54 a.m.]

MR. RODGER: Well, I could expand it to say eastern Ontario. (laughter)

MR. VYROSTKO: What has happened in the eastern region just very recently is that we have had some developers come and talk to us about proposals in that region. And we have said that as a result of where we are with respect to the transmission, we can't give them an answer whether we can, in fact, take those projects, but so far, that is not what we call a proposal that we have received.

MR. RODGER: Okay.

MS. PATTERSON: Could you refresh my memory, how many regions are there altogether?

MR. VYROSTKO: There are five wholesale regions. Since we have mentioned four, the fifth one is central region.

MR. RODGER: Q. Mr. Vyrostko, has Hydro advanced the construction of transmission facilities to accommodate a NUG proposal?

MR. VYROSTKO: A. Yes, transmission facilities have been advanced to accommodate, amongst other things, non-utility generation projects.

Q. When you say "among other things", it is not specifically just for the NUG in question then?

A. I don't believe it was specifically

just for the non-utility generation project there.

Q. That was part of the consideration, I take it?

A. Typically, if we would be advancing a transmission facility, the bottom line requirement there is that we have already identified the need for the transmission facility. And a NUG coming in earlier than when we need it, we would advance the transmission facility.

So we have advanced it because the NUG has been there, but the need for it has been identified for other reasons.

Q. Well, would Hydro advance the construction of transmission facilities solely to accommodate a NUG?

A. Depending on the circumstances, yes.

Q. And how would that be costed in to the avoided cost for NUGs? Would the NUG pick up the tab for that or would the ratepayers?

A. Typically, the non-utility generator would pick up that cost.

Q. Okay. Mr. Snelson, if I could ask you a question of clarification, if you could turn to page 3, please, of Exhibit 335. And this is from Volume 67, page 12060. Go down to line 17, I would

just like to read a few sentences. This is talking about transmission limits generally on the system.

On line 17, it reads:

"The fifth and last transmission limit that we have identified is one that runs through the Metropolitan Toronto area, generally to the north of the Metropolitan Toronto area, and you can think of it as being limiting to flows that sort of cross Yonge Street. There are several existing transmission lines at 500 kV and 230 kV in that area, and the flow that is of concern is that at times that transmission is fully loaded or will be fully loaded from the east to the west, and that can affect non-utility generation to the east of the Metropolitan Toronto area over to Ottawa."

So the problem you are identifying here is an east to west problem, correct?

MR. SNELSON: A. That is correct.

Q. Now, I also wonder if you could turn to page 5, and this is a response to AMPCO Interrogatory 2.24.9. And just over the page, on this

interrogatory, there is one section of the answer entitled, "Cherrywood transfer east towards Cataraqui".

And I take it that the problem here is a limit that goes west to east; is that correct?

A. Can I just read that for a second?

Q. Sure.

THE CHAIRMAN: While he is reading it, we can give it an interrogatory number. It will be No. 33?

THE REGISTRAR: 321.33.

---EXHIBIT NO. 321.33: Interrogatory No. 2.24.9

MR. RODGER: Thank you.

MR. SNELSON: Yes.

MR. RODGER: Q. And just to be clear, Cherrywood, that is in Scarborough, isn't it?

MR. SNELSON: A. Yes. That is in towards the eastern end of the general Metropolitan Toronto area. I am not sure that specifically it is in the Borough of Scarborough.

Q. Okay. I just wonder if you could explain to me how both these limits apply, how you can have west/east constraints and also east/west constraints.

A. Well, they, to some degree, address different time periods. They also are geographically

different locations. The flow that is discussed in the Cherrywood transfer east towards Cataraqui is a flow that is east of Cherrywood.

The flow that is being discussed with respect to the transmission that I was discussing is a flow that is between the Cherrywood sort of area and the area that is towards the west of Metropolitan Toronto. So we are talking about different interfaces.

I think the big point is that we are talking about different periods of time, different degrees of development of the transmission system and different degrees of development of the generation system.

So, for instance, the Cherrywood transfer east discussion talks about transmission lines that are going to be constructed in the early 1990s that will relieve that problem. So that is in an early 1990s' problem.

The addition of generation at Darlington alters the balance of east to west transfers and west to east transfers. And so generally speaking, any point on the system that is west of Darlington will see a big influx of power from the east as the Darlington generating station comes into service. So that will tend to reduce problems of transfers to the east.

The problems that we are talking about across the north of Metropolitan Toronto are sort of mid to late 1990s' problems. So we are talking about different time periods, different developments in the transmission system and different developments of the generation system.

Q. These examples we have just talked about, do they also show that transmission problems are dynamic, they are changing?

A. Certainly.

Q. If they are changing, would you agree that it is very difficult to predict where the problems are going to be down the road?

A. It is not easy but that is the function of transmission system planning. And through load forecasts and the forecasts of loads by region and through plans for generation and transmission additions, then that future situation is forecast and is planned for. So, it is uncertain, yes, but it is planned for.

Q. I guess my concern is that -- let's take a situation where you tell an independent power producer today - you say yes, location 'X' is an appropriate place for your NUG. There's no transmission problems. But if constraints change from

time to time, maybe two years down the road, that NUG is going to be in a location where there is a problem, there is a transmission problem. And with Hydro's own equipment, they can say, well, we are just not going to rely on that power. We can adjust for it.

Is Hydro bound to keep buying the power from the NUG and is that going to create further problems for the transmission system? That is the concern.

A. I think we would try in both the case of an Ontario Hydro generating plant and a non-utility generating plant to predict that it will be placed in a situation where transmission will not be a constraint and to build the transmission in time so that it can accommodate that plant, and in both cases, that is the objective.

Q. Is this last constraint that you talked about in your evidence in-chief for this panel, is that a new development?

A. The constraint through the middle of the Metropolitan Toronto area?

Q. Yes.

A. It is a constraint that has been predicted for some time. It was certainly known at the time the Demand/Supply Plan was written. And there is

a planning process in place to address that and the Sudbury to Toronto constraints that I talked about which is called the "Sudbury Toronto Area Transmission Reinforcement", STATR. It has not quite start but it is very close.

Q. In that situation that I described, the hypothetical if you put in a NUG, the transmission is fine now and you have a problem a couple years down the road, what do you do in that case? Do you continue to purchase electricity from the NUG and shut down the Hydro system that would also be perhaps causing a problem on that line? I guess I am unclear as to what you do in that situation if that develops.

A. I think it would depend on the circumstances.

Q. Well, in the hypothetical, you locate this NUG by a near transmission facility and it is clear now. It becomes the problem. Do you shut down that NUG or tell the independent power producer, we just can't take any more power from you right now because of this problem and we won't be able to take any until it is rectified?

A. In the ultimate, we have clauses in our contracts which permit us to shut down NUGs if they are a danger to system security or to safety. I would

not expect those clauses to be exercised for any very large proportion of time. And there are other ways which one may be able to address the problem if it was to be a continuing problem.

Q. So if Hydro maintains that option in the contracts, I take it if that needed to be done, the NUG gets shut down and the NUG just doesn't get paid until the power can be brought back on line again; is that correct?

MR. VYROSTKO: A. If, in fact, we shut a NUG down due to system requirements, they would not get paid, that is correct.

Q. All right. Thank you.

I would like to turn now to reliability of NUGs - I have a few questions - and particularly incapability factors.

Mr. Brown, I believe, in your evidence, you testified that for high-efficiency cogeneration, the capability factor is 80 per cent is that right?

MR. BROWN: A. That's correct.

Q. And the incapability aspect of that is 5 per cent for forced outage rates, 10 per cent derating of steam and 5 per cent planned outages; is that right?

A. That is correct.

Q. Now, this leaves open the question of incapability for other NUGs. And I just want to go through a few parts of Hydro's evidence. There seems to be a few figures at odds and I just want to see if you can clarify it for me.

First, if you could turn to page 6 of Exhibit 335, and the very last line of that page. This is page 10 of Exhibit 83. Under the heading, "Capacity Factor and Dependability", the last sentence read:

> The dependability assumed for all thermal facilities is 90 per cent.

And if you now go over to the next page, page 7 of Exhibit 335, which is page 40 of Exhibit 83, under Section A3.3.3, backup power charge, the first sentence reads:

> Cogeneration systems are very reliable, greater than 90 per cent.

First of all, Mr. Brown, does dependability in Exhibit 83, does that mean the same thing as capability?

A. No. There are different numbers.

Q. What does dependability mean?

A. Dependability is the amount of capacity we expect to have on over the peak hour in a year which is usually our winter peak.

Q. What does capability mean then?

A. Capability is a number used to estimate the energy contribution from that NUG.

THE CHAIRMAN: Then is it 90 per cent of 80 per cent?

MR. BROWN: 90 per cent is dependability.

THE CHAIRMAN: No, but then I take 90 per cent of 80 per cent, is it?

MR. BROWN: No. They are independent.

THE CHAIRMAN: They are independent.

MR. RODGER: Q. Would it be fair to the characterize dependability as 1 minus DAFOR?

MR. BROWN: A. I believe for an Ontario Hydro station, that might be appropriate.

Q. Why wouldn't it be appropriate for NUGs?

A. The numbers I am using, I am trying to use Ontario Hydro terminology to incorporate NUG reliability and capability. The steam derating factor which is included in what we called a DAFOR is an annual number. It essentially reflects the fact that these high efficient thermal-matched non-utility generators will not be operating at full load during the summer periods, but we do expect over the winter peak that they will be operating at full load.

Q. So the steam derating is planned; whereas in traditional terminology, the DAFOR means a sudden outage, an unplanned outage; is that fair?

A. The DAFOR is essentially a forced outage rate that incorporates forced outages that completely shuts down the unit and forced deratings on the unit.

What I have incorporated in my number is the forced outages plus the steam derating factor which is not really a forced outage. It is following the process demand of the industry.

Q. Just so I am clear, with the steam derating, that part is planned. They know it is going to be down every summer?

A. It is not planned. The unit is not running at full load. It is following the steam demand. It could be shut down for Christmas holidays that we shut it off, but during the summer, there is no thermal heating required in the building, so the cogenerator would have to operate it at less output and then be derated by a certain factor.

I would expect an individual industry would be able to predict this steam following, I think is the terminology, for a particular year, but there is an element of uncertainty in there.

MR. RODGER: Just give me a minute, please, Mr. Chairman.

[11:15 a.m.]

Q. Just let me take you through a few parts of your evidence and see if I can get clarified on this.

Could you turn to page 8, please, of Exhibit 335? And this was a response to Interrogatory 2.2.22. Perhaps we should give that a number.

THE CHAIRMAN: 2.2.22?

MR. RODGER: Yes.

THE REGISTRAR: 321.34.

---EXHIBIT NO. 321.34: Interrogatory No. 2.2.22.

MR. RODGER: Q. This document is entitled "1990 Forecast of Reliability Indices For Use in Corporate Planning Studies", dated April, 1991.

I believe this document is used for corporate planning purposes at Hydro; is that correct?

MR. SNELSON: A. Yes, it is.

Q. And certainly the NUG plan is a key part of the overall system planning, I take it?

A. It is an important part of our system planning.

Q. On page 9 you have Table 13 from that report, and this shows the forecast of incapability

factor for the median load, and this is for the thermal stations, CTUs, and this shows a long-term incapability factor of 10 per cent. Is that a fair reading of it, what that means?

A. Yes, that is correct.

Q. Now, in this case, then, Mr. Brown, you are saying that that doesn't mean 10 per cent -- or, sorry, 90 per cent dependability, because you are saying that "dependability" and "capability" are different things?

MR. BROWN: A. First of all, my statement was in regard to my non-utility generation incapability forecast where I am trying to bring NUG terminology into Hydro terminology, and maybe Mr. Snelson will comment on page 9.

Q. Maybe before Mr. Snelson answers that, why could you not have a consistent terminology?

A. Hydro units -- Ontario Hydro units do not have process requirements.

Q. And that's the only reason?

A. That's correct.

Q. Sorry, Mr. Snelson?

MR. SNELSON: A. Can you just repeat the specifics of your question?

Q. Well, this Table 13 shows 10 per cent

incapability, and I am wondering whether that means the same thing as Exhibit 83 when it talked about a 90 per cent dependability for all thermal units.

A. "Incapability" is defined in this document as being the portion of time that the unit is unavailable or the equivalent portion of time the unit is unavailable in the year. That is not exactly the same idea as Mr. Brown's "dependability".

THE CHAIRMAN: What do you understand "dependability" to be?

MR. SNELSON: I believe Mr. Brown indicated that "dependability" was -- in his NUG forecast was the expected output of the unit at the time of winter peak, and perhaps he could confirm that.

MR. BROWN: That is correct. The incapability factors in this exhibit are used to calculate energy, and dependability is used to calculate the capacity over the peak hour of the year, and the two are separate studies that are done by System Planning.

MR. SNELSON: I would comment that we are moving away from the use of the dependability number that is given in the NUG plan towards the use of the incapability factors that are shown on, I believe, the next page of our exhibit.

MR. RODGER: Q. Table 14?

MR. SNELSON: A. Table 14, which is on page 10 of your Exhibit 335, which is in the direction of increasing the degree of consistency between the way in which we deal with non-utility generators and the way in which we deal with our own generating capacity.

Q. And certainly this table which is for natural gas-fired cogeneration NUGs, this certainly shows an incapability factor for NUG cogen of 20 per cent and forced outage rate of 15 per cent; is that right?

MR. BROWN: A. The DAFOR in this particular case is, as I mentioned, a 5 per cent forced outage rate and a 10 per cent steam derating.

MR. SNELSON: A. That is shown in the notes to the table.

Q. Could you tell me, Mr. Brown, where do these figures come from in Table 14? How do you determine this?

MR. BROWN: A. It is a review of U.S. experience, it is a look at Ontario Hydro's own estimate of combined-cycle technology reliability, and unfortunately there is very little Ontario information to support this at this time. We are working on improving that.

Q. So certainly it just didn't come -- Table 14 didn't arise out of Hydro's own experience; it is entirely looking to other jurisdictions and your own estimates?

A. Combined-cycle technology is new to Ontario.

Q. Now, do I understand it correctly then that the Table 14 data for your incapability factor, that applies to all types of NUGs, be they high efficiency or low efficiency?

A. These are for thermal-matched non-utility generators.

Q. How about non-thermal matched NUGs?

A. As I mentioned to the previous Intervenor, we are still looking at that type of non-utility generator, and we expect the number to be less than 20 because the --

Q. Less than 20?

A. Because the process derating is not a significant factor in the output of those units.

Q. When do you think you will have those figures determined for the lower efficiency cogeneration?

A. They will have to be developed to produce 1991 NUG plan, initial estimate. Again, we

don't have a lot of information to support that.

The 5 per cent planned outage and 5 per cent forced outage is pretty well industry standards for Ontario Hydro and all other utilities. It is the impact of the process on that number that we do not have a lot of data to support.

Q. Maybe you could help clarify another matter.

On this Table 14 we have got the DAFOR of 15 per cent, and you have said how that's broken down. If you could turn over to the next page, please, page 11 of Exhibit 335, and this is taken from Volume 18, page 3221, and it is Mr. Taborek's evidence, and from line 12 the question was asked:

I am interested in the forced outage rates assigned to the various units and --

Answer: The NUG units?

Question: Sorry?

Answer: The various NUG units.

Question: Yes.

Answer: 10 per cent.

Question: 10 per cent?

Answer: Yes.

Could you tell me what the correct figure

is, given this testimony in Table 14?

MR. SNELSON: A. Perhaps I can deal with that.

Q. Okay.

A. I believe that Mr. Taborek was discussing the reliability studies that went into determining the 24 per cent reserve requirement, and that used earlier versions of a variety of sources of data than the 1991 forecast of outage indices that we were just looking at, and he was discussing the numbers that were in use at that time.

The numbers that would be used in the reliability model and reliability studies that would be done today would be those that were shown in the tables that we have just been looking at.

Q. All right. How does this 5 per cent forced outage rate, how does that compare with Hydro's hydraulic units?

A. The interrogatory that you referred to,--

Q. Yes?

A. --which I believe was 2.2.22, also has tables in it for hydroelectric units, which is the forecast for hydroelectric units, and that is based upon past experience and that shows the DAFORs,

"derating adjusted forced outage rates", for hydraulic units in a number of different groups, but the composite of them all is in the range of 2-1/2 to 4 per cent.

Q. Are there any higher than that?

A. There is a Group B, which for a few years is forecast to have an outage rate of 4.8 per cent.

Q. Would it be fair to say that out of all the forms of generation generally speaking the hydroelectric are the most reliable?

A. Hydroelectric generating units are certainly mechanically very reliable.

Q. And that 4.8 per cent, that is very close to the 5 per cent that you are anticipating that is the DAFOR rate for NUG cogen; correct?

A. 4.8 is very close to 5.

Q. Is that reasonable to have those estimates, you have a long history of hydro electric, very reliable, 4.8 per cent; you have a new technology you don't know much about and you are anticipating that that forced outage rate is going to be 5 per cent?

A. Well, combustion turbine units are not a new technology, and I'm afraid I couldn't particularly comment on whether -- the comparison, you

are looking at two very different sorts of technology.

MR. RODGER: This might be a good time to take a break, Mr. Chairman.

THE CHAIRMAN: All right. We will break for 15 minutes.

THE REGISTRAR: The hearing will recess for 15 minutes.

---Recess at 11:28 a.m.

---On resuming at 11:50 a.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

THE CHAIRMAN: Mr. Campbell?

MR. B. CAMPBELL: Mr. Chairman, in speaking to Exhibit 333 this morning I clearly misspoke myself. I don't believe the Panel 6 "Statements of Concerns" have been required to be filed yet. That date was extended.

I expect there has been a wide distribution of Exhibit 333, and I know that for some people it just hasn't arrived yet. We are getting some copies. I have asked that some copies come up today, and we will make sure that the distribution is wide and appropriate, as I expect it already has been. I just don't have the details.

THE CHAIRMAN: Thank you. Mr. Rodger?

MR. RODGER: Thank you, Mr. Chairman.

Q. I have one follow-up question with respect to transmission constraints which I overlooked when I went through that section first.

When we talked about how some NUGs were downsized because of transmission constraints what regions were those proposals in?

MR. VYROSTKO: A. I believe they were in northwestern region and northeastern region.

Q. But not the western region?

A. I don't believe so.

Q. Okay. I take it then the central region hasn't been identified in any of my questions with respect to transmission, so there are no problems in that region with respect to NUG projects being either rejected or downsized; is that right?

A. Again, I think it depends on the location. There in fact could be some problems, depending on where the location is.

Q. So there could be some --

THE CHAIRMAN: You are talking about the future, not the past?

MR. VYROSTKO: That's correct, the future, yes.

MR. RODGER: Q. But to date there has

been none in the central region?

MR. VYROSTKO: A. No, that's correct. There have been no problems to date.

Q. Thank you. Just a couple of other questions with respect to forced outage rates.

Could you tell me, Mr. Snelson, what forced outage rate is Hydro using for its various types of NUGs in the system reserve studies?

MR. SNELSON: A. Generally speaking, the system reserve studies were used for all forms of generation, the most recent set of forecasted reliability indices that are current, the most recent at the time at which studies were being set up to be performed.

Q. So is there a number then for...?

A. The numbers that would be used in studies done today are those in your response to Interrogatory 2.2.22 that we were discussing.

Q. And that then is the 15 per cent figure, the 5 per cent for forced outages and 10 per cent to the steam process derating?

A. I believe that's the case.

Q. What about the straight major supply NUGs that don't have the steam component?

A. I don't believe that we have had to

do any reliability studies where they have been separately identified as yet.

As Mr. Brown has said, we will be addressing in future editions of this corporate prediction what we would predict as being the reliability performance of those sorts of units.

Q. Lastly on this subject, does Hydro have any data on the forced outage rates and the maintenance outage factors for waste heat steam boilers and their auxiliaries for cogeneration units?

MR. BROWN: A. Our data is on the overall system, not individual components. The reliability numbers we are quoting are for the entire system, so we do not have information on a waste heat recovery boiler.

Q. You don't break it down to that specific?

A. Not yet.

Q. Do you plan to do that?

A. Our plans right now are just to get the data in terms of forced outages and planned outages and availability. I think it is very important to start breaking down, much like utility systems do, in the future.

The North American Electric Reliability

Council has now requested utilities to report NUG data, and that would be one component of that. As of August of this year, no NUGs are in that data base yet.

Q. Have you got any kind of estimate at all how long it's going to be before that data is available? Are we talking five years, ten years? Is it possible to guesstimate at this stage?

A. I can't.

Q. It could be a long, long way off?

A. In terms of producing reliability indices, we are just getting the aggregate for the system.

Q. So would you agree with me it could be a long, long way off?

A. That's correct.

THE CHAIRMAN: Weaving through this discussion is the absence of data which I must say surprises me a little bit.

There aren't that many projects in the number of projects that we are talking about. Is it because you haven't asked for the data, or is it because it hasn't been furnished to you, or why is it you haven't got the data that you think you need to do some of these?

I am not talking about this particular

question, but it has been sort of a constant problem in many of the questions you have been asked.

MR. BROWN: To start with, a lot of the proponents feel that detailed information is confidential and they're reluctant to give it out as a general rule. We are trying to take this information and aggregate it to provide information.

In 1982 we didn't have any NUGs selling to us, so there is really no information, and it wasn't until 1989 we started seeing large units on the system. They are having teething problems, so it is difficult to get data off that. The ones that were in service that we mentioned, the historical load displacement, since they weren't selling to us we had no information of our own and in general the proponent didn't keep that information either or was reluctant to give it to us.

MR. RODGER: Q. Perhaps I could follow up on that point.

Why doesn't Hydro make it a condition of the contract that the NUGs are going to provide this information? If you say they are unwilling to because of confidentiality or whatever, why doesn't Hydro just make it a condition of the contract?

MR. BROWN: A. My comment was based on

the past, and I think one of the reasons was we never asked for it.

Since now I am starting to collect this information, recognizing its importance, I have asked even the historical load displacement generators for this information, and not one has said they would not provide this information.

Q. So is that request now part of every contract that Hydro will enter into with a NUG from here on in, will have that request?

A. It's not in the contract, but I remind you that we have other agreements with these NUG proponents in addition to the contract. So it is not in the contracts, and to date NUG proponents are willing to give us this information.

Q. Would you agree that it would be a good idea to have it in the contract so that nothing is left to chance and you know you are going to get the information?

A. We considered that option, and our decision so far, since we haven't had a problem, is we are going to leave that to the operating agreement with the non-utility generator.

THE CHAIRMAN: I am a little confused. I think you said a few moments ago there was some

information that was not provided because it was confidential, and then you said information hasn't been refused and will be forthcoming.

Where is the line drawn?

I would think that most of the information that we have been talking about of outages and so on, I really don't understand why it would be confidential.

MR. BROWN: It is confidential between two people who may be competing. Say, a pulp and paper industry may not want to share their costs of production with their next door neighbour.

In that regard, they don't want somebody else to find out about it, but I think they're willing to provide it to us. Before '88 we weren't asking for it, and they weren't keeping it.

[11:58 a.m.]

THE CHAIRMAN: So, it is not a question of not providing it to you. It is a question of you not disseminating it. That is the confidentiality.

MR. BROWN: That is what is happening now, that is correct. And the confidentiality issue is still a big issue in the United States on them trying to collect the data because I could use that kind of information if it was available, but that is just not

around either.

THE CHAIRMAN: I see.

MR. RODGER: Q. One final question on this point. In terms of NUG cogenerators that are on the system now, how about the performance data for those units?

MR. BROWN: A. This information was -- Interrogatory 5.14.141, which I believe already has an exhibit number, provided some information.

Q. Could I get that number again, please?

A. Sorry, 5.14.141.

Q. Thank you.

THE CHAIRMAN: That is 321?

THE REGISTRAR: 321.15, Mr. Chairman.

THE CHAIRMAN: Thank you.

MR. RODGER: Q. I wonder if you could turn to page 15, please, of Exhibit 335. This is AMPCO Interrogatory 5.24.13.

Can I have a number, please?

THE REGISTRAR: 5.34 -- what is the last digits?

MR. RODGER: 13. 5.24.13.

THE REGISTRAR: Thank you.

That will be 321.35.

MR. RODGER: Thank you.

---EXHIBIT NO. 321.35: Interrogatory 5.24.13.

MR. RODGER: Q. The first part of this question states:

> Is it technically and environmentally feasible to operate the gas turbine generator part of a cogeneration unit without producing steam? Are all cogeneration proponents required to operate in this mode if there is no demand for steam in their plan?

And if you go down to the second paragraph of the answer, it states that:

> It is technically feasible to operate a gas turbine without producing steam.

I wonder if you could tell me what impact does this have on the cost of producing a kilowatthour of electricity for these units that have no steam demand.

MR. BROWN: A. I don't believe we studied that particular scenario. Our evidence to date would suggest that in the past when we did the 1990 NUG plan, they needed this high efficiency to be viable. The exact numbers, I am not sure.

Q. Would it be fair to say that

certainly the cost would go up?

A. That is correct.

Q. Could you tell me, Mr. Brown, how many megawatts of cogeneration out of the 1,957 megawatt figure that we just received - that is for industrial cogen - how much of that can be operated with no steam demand? I should have put no demand for processed steam.

THE CHAIRMAN: Just for the record, the 1,957 refers to Exhibit 331B, I take it?

MR. RODGER: Yes. Thank you, Mr. Chairman.

THE CHAIRMAN: Column F.

MR. BROWN: As a minimum, 818 megawatts could be provided without using steam. These are the large proposals that have accepted rate offers with Ontario Hydro. These generally are not thermally matched and have been designed such that they do not have to provide processed steam if that was a condition at the time.

In addition to that, even the thermal matching units, assuming combined-cycle technology, could shut off the steam turbine and just run a gas turbine and exhaust the heat to atmosphere and it is possible, I would think, that they could even bypass

the process and run the whole unit and somehow condense the steam if that is so designed.

MR. RODGER: Q. Okay. So that is 818 megawatts for no demand for processed steam.

How about --

THE CHAIRMAN: I don't get paid to do this, but would why wouldn't it be the Column 8, 791, in that exhibit?

MR. BROWN: 791 is the addition above thermal matching. And since these large proposals are built with a condenser, they are able to bypass the process and condense the steam without actually sending it to process. So the full output of the unit could be run at any one time. In that mode, they are essentially a major supply NUG, a combined cycle with no cogeneration.

THE CHAIRMAN: Well, I thought that is what you are being asked for, how much would not have any steam component in it; isn't that right?

MR. BROWN: Yes. The thermal matching portion of that, the 111, for the large designs, they can bypass that process and still produce electricity. So you can get the full 818 out of those projects even without cogeneration.

THE CHAIRMAN: All right.

MR. RODGER: Q. So the 818 megawatts is with no demand for processed steam.

How about if the --

THE CHAIRMAN: That is the figure in Column B; is that right?

MR. BROWN: That is correct.

MR. RODGER: Q. How about if the processed steam demand is reduced 50 per cent?

MR. BROWN: A. The 818 was under the assumption of zero process. For these particular projects, the process does not affect the output. They can essentially vary the output to process without changing the megawatts. It is either going into the process or it is going into a condenser and they can control that.

Q. I think, Mr. Brown, I am referring to the cogeneration units that have a higher percentage of steam. It is as part of their operation.

And if you reduce that by half, how many of those NUGs can run with only half the steam load?

A. It would depend on the design in that particular case. Like I mentioned, they can always run the combustion turbine to produce the megawatts. What they have trouble with, especially as the steam load increases, is how much of the steam turbine they can

run.

It is largely a function of how much condensing power they have. If they can condense the whole output of the steam turbine, they can get a full output. If the condenser is designed for 50 per cent process, 50 per cent waste, then that will derate for sure.

MR. B. CAMPBELL: Mr. Chairman, just while my friend is conferring with his advisor, do you have adequate description of what is contemplated when Mr. Brown is speaking about condensing the steam, that this makes adequate sense, because we might as well clear it upright now? And he could explain what the condenser does and how it is hooked into the system and the steam flow can go either way, I think, as I understand his evidence so far, but that only makes sense if you understand exactly what all of that entails. And if it will be helpful for him to give a little more detail on that, perhaps now is a good time.

THE CHAIRMAN: I have a rough idea. I wouldn't want to write an examination on it, but I have some idea of what they are talking about. (laughter)

MR. B. CAMPBELL: Maybe while my friend is conferring, if Mr. Brown could give a bit more of a description, I think it may -- there are a couple of

different diagrams that help illustrate this I know in the evidence in various places.

But Mr. Brown?

MR. BROWN: If we turn to page 35 of Exhibit 335, there is a --

THE CHAIRMAN: Just a minute now.

MR. BROWN: One of the overheads I used in my evidence in-chief, on the bottom is the lower efficiency cogenerator. And there, it shows steam being sent to process and steam being sent into the lake for cooling.

And the plant itself is a heat recovery steam generator which is producing electricity from steam and a combustion turbine which is producing the large part of the electricity.

That plant can be run independent of the items on the left, which is a process steam in a cooling. The only thing changing is how much is going to process and how much is being cooled through the lake.

So in the worst case, zero processed steam, the plant can still run at full output, which is the 886 megawatts I mentioned, and all the steam coming off the steam turbine could be condensed into the lake rather than 20 per cent that is shown in this figure.

As the process demands more steam, thermal energy that is being exhausted into the lake could then be diverted and used in a process. And if it is really efficient, there will be nothing going into the lake and everything going to process. I don't know if that makes it any better.

MR. B. CAMPBELL: Well, just looking at that bottom diagram, would it be correct from what you are saying that where the lower efficiency cogenerator, that is the kind that is included in the 818 megawatts that you referred to, if that processed steam was shut down entirely, if you just kind of remove that processed steam, what you are saying is that there is sufficient equipment installed for steam condensing that it could go through the condenser and thereby be cooled by the lake water?

MR. BROWN: That is correct, with no impact on the electricity output.

MR. B. CAMPBELL: Then there would be presumably other permutations and combinations where the ability to do that would be entirely dependent on how much installed capacity there was for steam condensing.

MR. BROWN: That is correct.

MR. B. CAMPBELL: I hope that is a little

bit helpful.

MR. RODGER: Q. Well, perhaps this might illustrate my concern, staying with page 35. For the typical high-efficiency cogenerator that has 65 per cent processed steam, could that cogenerator continue to operate if the processed steam demand fell by 50 per cent?

MR. BROWN: A. Normally, the output would have to go down. In this particular example, all the exhaust is going to process, so the unit would have to derate itself to provide the process with the required amount. And it is very similar to this process derating that I used in my incapability factors.

Q. So in that case, the electrical output would be substantially reduced and the cost of producing a kilowatthour of electricity would go up in that scenario; is that fair?

A. Per kilowatt it would because obviously, he has over installed his unit.

Q. All right. Just one last point staying with page 35. Out of that 1957 megawatts, the revised figure, how many of that amount, how many megawatts are reflected by this typical high-efficiency cogenerator that has 65 per cent processed steam or

higher?

A. It is roughly about half.

Q. Okay. Thank you. I wonder if we could go back to page 15, please, and this is back to Interrogatory 5.24.13. And the last sentence of the question reads:

> Is Hydro prepared to pay a premium over the negotiated purchase price to offset the additional cost of generation? With gas at 2.80 million cubic feet, how large approximately would the required premium be?

And if you go to the first paragraph in Hydro's response, it reads:

> Ontario Hydro does not prescribe any preferred configuration in any cogeneration proposal. Hydro is not prepared to pay any premium over the negotiated purchase rate should additional cost be incurred as a result of decreased or disappearing steam requirements.

If circumstances occurred where a cogenerator has lost the steam load and the owner refuses to operate it because the price paid by Hydro

wouldn't be enough to meet his costs, under that circumstance, what would or could Hydro do to ensure that that electricity is supplied to the system?

MR. VYROSTKO: A. First of all, when we negotiate a contract with a cogenerator, assuming he is a third party developer with steam on the one side and electricity on the other, one of the first things that we try to ensure is that the proponent, the third party developer, has a long-term steam contract with the steam host. That then gives us assurance that the steam host has looked at the overall business of buying steam from that third party developer and is prepared to go into that long-term relationship.

With that, we then would get into a long-term contract and the risks, therefore, of the steam host disappearing rests with the proponent; therefore, we would not be prepared to, or we haven't had to, and I don't think we would at this point in time, do anything with respect to renegotiating that contract.

Q. And what about making up that supply? If the developer or whoever is in control of the NUG just says, I am just going to lose too much money on this, what does Hydro do to make up that supply in that case?

A. Well, I think in the situation if we were to lose a project as a result of whatever on the proponent's side, then we have less available capacity coming from a non-utility generator out of the -- let's assume it is the 3100 megawatts. And so, therefore, to bring the level back up, we would be going in, trying to get additional megawatts from non-utility generators.

The impact is that you have then lost a portion of that 3100 due to the failure of that project. But at this stage, we believe that because of the diversity of supply, the impact on the entire system is minimal.

Q. All right. This leads into the next question. If you could turn to page 16, please. This is Interrogatory 5.24.12, which, I believe, should become 321.36?

THE REGISTRAR: That is correct, 321.36.

---EXHIBIT NO. 321.36: Interrogatory 5.24.12

MR. RODGER: Q. And this question asks:

Has Hydro performed any studies to determine the effect of an industry-wide shutdown, say, in the pulp and paper industry, on the assumed reliability of cogeneration? Shutdowns might occur from

industrial action, environmental considerations, economic conditions and the like. Please supply the details of any such studies or if they are not available, please comment on such eventualities and their probable impact on Hydro's system load meeting capability.

And basically, the response says that a shutdown would not affect Hydro's load meeting capability even if all the NUG output in that industry were lost because the generator loss would be offset by the drop in demand in that industry.

Is that a fair characterization of the response?

[12:20 p.m.]

MR. VYROSTKO: A. That's correct.

Q. And would you agree with me that this answer presupposes that the pre-shutdown NUG output closely matches the electrical load of that industry?

A. That's correct.

Q. Using the example of the pulp and paper industry, could you tell us the extent that the NUG output from cogeneration matches the electrical demand of that industry?

A. I would not know that offhand.

Q. So do you do that on an industry-by-industry basis? Is that data available anywhere?

A. We do have the breakdown of the generation by industry sector in Interrogatory 5.9.48.

THE CHAIRMAN: 48?

MR. VYROSTKO: 48 that's correct. Four-eight, 5.9.48.

THE REGISTRAR: Thank you.

MR. RODGER: Q. I will tell you my concern --

THE REGISTRAR: That would be 321.37.

---EXHIBIT NO. 321.37: Interrogatory 5.9.48.

MR. RODGER: Q. Because I will tell you my concern if the NUG output isn't matched with the electrical demand.

You could have a situation where you have let's say a 50 megawatt cogen unit in a pulp and paper mill but only 10 megawatts of that goes to the mill, and you have more megawatts of steam process being used in the mill than you do have megawatts of electricity. And let's say, for example, there are poor prices for paper in the pulp industry so it shuts down. The mill shutting down could shut down the whole NUG and therefore Hydro loses the full amount of the NUG, loses

the whole 40 megawatts that's going into the system.

That's the concern if they're not matched.

MR. VYROSTKO: A. There could be situations where in a particular circumstance if the plant were to shut down the availability of the third party developer or the cogenerator to continue to operate, as has been said before, would not be there. So then, in that circumstance the generation would not be available.

DR. CONNELL: One question. In the event of a bankruptcy and/or a forced sale does Hydro have in the contracts any purchase rights or rights of first refusal?

MR. VYROSTKO: It depends on the type of contract that has been negotiated.

For instance, when we negotiate -- and part of negotiations includes one of our financial assistance options. We would be asking for security, and typically the security is the plant, the assets of the plant, and so we would be second to the prime lender with access to that plant.

THE CHAIRMAN: But you don't have specific buy-back or first right of refusal provisions?

MR. VYROSTKO: We -- there are a couple

of contracts where in fact we have negotiated a buy-back of the project, but, generally speaking, that is not -- that's not the norm.

THE CHAIRMAN: To date, in your experience has this happened? Has any NUG operator gone out of business and ceased to provide you with its contracted power?

MR. VYROSTKO: No, not one has yet.

MR. RODGER: Q. I wonder if you could go back to page 1, please, of Exhibit 335, back to the chairman's speech, and the fourth paragraph from the bottom reads:

> For this reason we plan in the future to move away from our current open door approach towards a bidding process. This will help us to clearly communicate our needs to you. We will be asking for bids in the future to supply specific amounts of electricity with specific in-service dates and in specific locations.

What is the current practice with respect to specific in-service dates and specific locations?

MR. VYROSTKO: A. Currently, we -- except for this interim moratorium that we have, as we develop our new guidelines for high-efficiency

cogeneration, from last year until that point in time we have been accepting projects through what we call an "open door policy". In essence, if a developer has a proposal he will come in and submit the proposal.

The in-service date of that project is determined by the proponent and the location is determined by the proponent.

Q. So when does Hydro intend to move then to this system that is being described by the Chairman?

A. We haven't determined when that would take place. We had to stage this through a number of activities.

The first activity is now developing a better definition or different definition of "high-efficiency cogeneration", and then to work with the industry to have the preferred options being put forward, and that is the high-efficiency cogen and the renewables.

If we in fact see that those projects are coming forward in a reasonable way to satisfy our requirements for the 3,100, we may not need to go to the competitive bid process. If we find that we are not succeeding for whatever the reason then we would then have to look at some competitive bidding process.

Q. So for the foreseeable future, at least, Hydro is going to maintain the open solicitation?

A. I believe that we will be doing that in the foreseeable future.

Q. If I could just ask you perhaps a more general question, Mr. Vyrostko?

You testified that these non-utility generation contracts, they could be for as long as fifteen, twenty, thirty even fifty years, and yet we have heard a lot about how there is just no reliable data around at this stage in terms of reliability factors for NUGs and so forth.

Isn't Hydro extremely concerned about relying more and more on this source of power and for such a long period of time with such little information available?

A. I would like to answer that question in sort of two ways.

On the one hand, I think we said a few times today that there isn't enough information available for projects that we have entered into contracts for, for reliability. They haven't been around long enough to collect that type of reliability.

However, I believe I said in my direct

evidence that non-utility generation is not new in Ontario, and, in fact, is not new to industry because electricity in Ontario started with private companies building their own electricity.

And I think if we go back and look at many of those what we call "traditional" non-utility generators their performance on their units has been very good, and there is all kinds of examples of industrial customers who in fact have had these, whether their hydraulic, whether they're wood waste, whether they're natural gas-fired.

So although we don't have data there is experience that has shown that they are reliable pieces of equipment.

Q. So you have got enough comfort based on the past track record with respect to NUGs?

A. Based on the past record and the quality of new equipment being developed by manufacturers, it has been more reliable in the past so I do have better comfort, yes.

Q. My next question, it is one that I originally asked Hydro staff at the Clarkson Control Centre which the Board and several Intervenors visited, and Mrs. Formusa suggested that I wait and ask this Panel.

When we were at that site visit we were advised by Hydro staff of the great importance that Hydro places on being able to constantly monitor the output of their various generating stations, and I can recall we were all taken to a room and we looked out onto a huge screen and we could see the constantly changing output of all the various units that Hydro has on its system.

My question then and today is: How is Ontario Hydro going to bring that same level of scrutiny to the various NUGs in the province that Hydro is proposing by way of its non-utility generation plan?

A. I believe by Ontario Hydro dealing with major supply NUGs as an option that is similar to our own options, brings that perspective into being.

I believe we said that major supply NUGs are in essence similar to Hydro options. They are larger. Therefore, individually they are now having a larger impact on their overall option, and therefore on the system, and therefore, there is that need to monitor them as we do with any of our options.

Q. So is it Hydro's plan for the major supply NUGs, would they also be incorporated into this control screen that we saw in Clarkson?

MR. BROWN: A. I can answer that

question.

The board you are looking at is all of Ontario Hydro's large units. There are some units for Ontario Hydro that aren't shown on there, such as the Trent River system.

It is our intent to put non-utility generation in the security side of Clarkson. We already have those in the detailed screens. I am not sure how far your tour went.

There is a particular screen that can be called up and shows the output of every non-utility generator that is monitored by the DACS system. At present we insist that DACS be put on all units above 50 megawatts. There is a grey area between 10 and 50, depending on how sensitive the system is to that unit. We can insist on DACS monitoring for those particular facilities.

Q. Did you say the system was DACS monitoring?

A. "Data Acquisition Computer Sub-system". That's the network that brings the information into Clarkson.

It is a cost the proponent has to pay as part of the connection cost, and we bring that information into Clarkson, and all units there -- I

think at the time of your tour there probably were four or five NUG units on the display, and obviously the system control person responsible for security has to know the output of NUG units to be able to dispatch the system and watch thermal and stability limits.

And we are working to get all future NUGs put in there, so they may not be on the big wall board, but he does have access to all the information.

Q. So that monitoring system will apply to all non-utility generation, regardless of the size of the project?

A. That's not what I said.

Q. What was the limit then of DACS?

A. It's over 50 megawatts.

Q. Okay.

A. And some are even less than that.

Q. What's the smallest size then that it can monitor?

A. Well, we can put one on any unit. It's the cost factor. I can get you a copy of that display, if that would suit your needs.

Q. That would help. I am just concerned that -- my understanding is there are a lot of NUGs in the Hydro plan that are going to be a lot less than 50 megawatts, and cumulatively over the next ten years or

more that is going to mean a lot of power, and I guess from our client's point of view we want to know how that is going to be monitored by Hydro in case problems develop.

A. Right now, if it is sensitive to the system - an example would be the northwest region - we would put, you know, smaller units would be put into the DACS system.

Right now, from the operator's concern, they were looking at 50 megawatts as being important to them in doing their business.

Q. Could you give me some idea of the cost involved in getting these units into that system? You said it was too expensive for under 50 megawatts?

A. Well, the proponent pays for these costs. It's charged back to the NUG proponent just like the transmission connection costs are.

THE CHAIRMAN: Would this be helpful in collecting the data that you haven't got, making use of this?

MR. BROWN: The data I use for reliability calculations is the billing data which we get now anyway for all units.

MR. RODGER: Q. If you could provide that information - I forget what you called it - that

would be helpful.

MR. BROWN: There is a screen that can be called up that has all the NUGs that are currently monitored and the output of those units, and that can be provided.

THE CHAIRMAN: That's an undertaking then, is it? Number...?

THE REGISTRAR: 322.17.

---UNDERTAKING NO. 322.17: Ontario Hydro undertakes to provide information re NUG outputs.

MR. SNELSON: With respect to your question, Mr. Chairman, as to the data, the data on how much a generating unit is producing at any point in time is important data.

It isn't sufficient for reliability analysis because it doesn't indicate the reasons why it is not producing at less than its full output, whether that's forced or planned or because of the process derating and so on.

THE CHAIRMAN: Okay.

MR. RODGER: Q. I would like to talk for a few minutes about lead times for non-utility generation. If you could turn to page 18, please, and that is in Exhibit 335, and this is taken from Exhibit 3, page 8-5.

The first full paragraph at the top of the page reads:

The NUG plan assumes that there will be no change in the regulatory framework which would have an adverse effect on the ability of NUG generators to obtain timely approvals.

Does Hydro continue to rely on this assumption?

MR. BROWN: A. Our NUG plan is based on all regulations that are current or known at the time.

Q. So this assumption as stated here applies today?

A. Well, this was done for the 1989 NUG plan, and yes, that comment was true for the 1989 NUG plan.

Q. And how is it different today then? I don't understand.

A. Well, there are new regulations since 1989 that we are incorporating in our forecast.

Q. Okay. Fair enough. But the main assumption remains the same?

A. Yes.

Q. Now, we know from Panel 2 that when Hydro intends to construct a CTU, then it either has to

submit the proposal to an environmental assessment or else it seeks an exemption order. I believe actually Mr. Snelson gave evidence on that; is that correct?

MR. SNELSON: A. I believe generally so, yes.

Q. And with respect to this --

MR. B. CAMPBELL: Sorry. Sorry, sorry, sorry.

I will have to check on this, but I think there are some circumstances under which there is an existing exemption under which CTUs can be installed. I know there is an existing exemption order in relation to that matter in particular for some very particularly defined circumstances.

MR. RODGER: I think that's right.

Q. Now, in this panel I believe it was Mr. Vyrostko, you stated that major supply NUGs are likely to have very similar effects in terms of their environmental effects, their social effects, as those technologies which Ontario Hydro might use.

Do you remember that evidence?

MR. VYROSTKO: A. Yes, I do.

Q. And another difference, I put to you, in terms of the process that Hydro has to go through and the process that independent power producers have

to go through, is that private proponents of NUGs don't have to go through environmental assessments unless they are so specified under the regulations.

Is that your understanding?

A. That's correct.

Q. Now, Mr. Vyrostko, when you talked about the process after you have adopted a particular project, you described the process involved, and you said:

> When the project opportunity is identified and we receive an application we would then refer the proponent to the appropriate government agency to facilitate the request for and the completion of all the necessary environmental reviews and permits.

[12:39 p.m.]

Do you remember that?

A. Yes, I do.

Q. And at present, I understand that your estimated lead times for NUGs are two to three years; is that right?

A. Two to three years after the contract has been signed, that is correct.

Q. After the contract has been signed.

Let me just digress for a second. Are you familiar with respect to a recent competition announced in Russia and the competition is for low power nuclear plants between 5 and 100 megawatts?

A. No, I am not.

Q. Okay. Well, let me put a hypothetical to you: An independent power producer submits a proposal to Ontario Hydro and it is for a small 50 megawatt nuclear plant. And I suppose for the purposes of my hypothetical, it doesn't have to be a small one since I understand your testimony to be that there is no policy limit on the size of a NUG. But let's just assume that it is a 50 megawatt unit.

I also want you to assume that Hydro needs a NUG of this size and that the avoided cost figures are such that it meets Hydro's economic criteria. It is said to be a viable project. And it will be situated in an area that it can be easily integrated into the Hydro system. There is going to be no transmission problems.

Would Hydro accept this proposal?

A. If the proposal was able to meet all of those regulations as stated and coming within the avoided costs, yes, we would.

Q. And as I understand the current

regulatory framework, that private nuclear plant, that wouldn't have to go through an environmental assessment unless it was specifically designated; isn't that true?

A. That is the way I interpret the Environmental Assessment Act, that is correct.

Q. Would you agree, Mr. Vyrostko, that if the regulatory regime changes and NUGs do have to go through environmental assessments, which I suggest to you is certainly reasonable given particularly the major supply NUGs, you have testified, have the same or very similar impacts as Hydro's own units, if they do have to go through environmental assessments, would you agree that it is going to have profound impacts on both the lead times for those NUGs as well as for the number of NUGs that are viable?

A. I guess I can't speculate with that because depending on the type of project, the environmental assessment process may not have significant impacts on the overall process.

We have, for instance, had non-utility generators that have had to go through the entire environmental assessment process.

Q. Would it be fair though to say that one potential result of NUGs going through environmental assessments is that the process could be

either so expensive or lengthy or introduce an element of uncertainty that the developers may not be willing to take that chance to go through that process and projects that otherwise might be viable they may say, no, we are not going to go through that?

A. That is a call that the proponent has to make, that is correct.

Q. And certainly you testified earlier on about class environmental assessments for small hydro projects; I believe that was your testimony, wasn't it, Mr. Vyrostko?

A. That's correct.

Q. So certainly, there are regulatory changes happening in this area with respect to independent power and environmental assessments?

A. That's correct.

Q. I guess my question to you, given what I read from Exhibit 3 about your assumption, how confident are you today about that assumption that there won't be any changes of this regard with respect to independent power projects?

A. Again, I guess I would just like to sort of put that statement to context. When the plan is put forward, we would assume all the expected regulations that we can think of being in place at the

time we do the plan. Because we do the plan on an annual basis, we then have the opportunity to reflect any new regulations into the next plan.

And for instance, as Mr. Brown explained, in the 1991 plan that we are looking at completing, he is reflecting into that changes to, for instance, the municipal solid waste, the fact that there is currently a ban. He is reflecting the fact that there are difficulties with respect to getting hydraulic projects approved for a lot of different reasons.

But once he does the plan, he assumes that the changes that he has reflected into the plan then stay for the duration of the plan. And I think that is how the statement was made.

Q. Mr. Brown, perhaps you could tell me, of those changes that you have incorporated into the new NUG plan, has that changed Hydro's estimate for lead times for NUGs or is it still two to three years?

MR. BROWN: A. I do not use lead times in determination of the NUG plan. It is based on long-term projections.

Q. But certainly, that lead time is important for Hydro's system planning purposes?

A. It is for the short term, that is correct. And in the short term, the information we are

obtaining are from NUG components on their estimate of when they go in service.

Q. Sorry, they are not from --

A. They are from the NUG proponent. They are not my estimate. They are the proponent's estimate of when they believe they will be going in service, and that is assuming that before they come to us, they are looking at all the environmental approvals they have to go through and that will be factored into that date.

Q. Does Hydro have any indication from independent power producers that they are starting to think about environmental assessments and what that is going to do to their estimates of lead times and in-service dates and that type of thing?

MR. VYROSTKO: A. I think that the various changes that are occurring around the world, I would think from an environmental perspective, are, in fact, being considered by the non-utility generation industry.

I know that there have been some discussions, for instance, at the Non-Utility Generation Advisory Council, with respect to new regulations coming forward. So, I would think that the industry is, in fact, considering those as part of

their overall approach to new projects.

Q. And with your discussions with independent power producers, what are they telling you about changes to lead times as a result of potentially having to go through environmental assessments?

A. I think that a number of the developers see that the lead times could be longer and, in fact, there could be some costs added to their overall project if, in fact, the environmental approval process were to substantially change from what it is today.

Q. Thank you. I want to leave lead times and talk about fuel prices for a few minutes.

Now, we have heard a lot of testimony to date regarding the importance of natural gas prices and how, in large part, this is the reason why we have an extra 1,000 megawatts; that Mr. Eliesen announced is that gas prices are lower this year; is that fair?

A. That is fair.

Q. Could you tell me, Mr. Vyrostko, what fraction of the current viable NUG projects would fail the viability test if the price of natural gas rose by 50 per cent, 100 per cent and 150 per cent by the year 2000?

MR. BROWN: A. I believe in the 1990 NUG

plan, graphs were provided on the sensitivity of natural gas. And in addition, a specific one relating to megawatts versus gas price was provided in Interrogatory 5.9.78.

Q. So I could find out the answer to my question I just put to you in that interrogatory?

A. No. In terms of the 1990 NUG plan sensitivity to natural gas was provided. I believe your question was on the new projects that are included in the 1,000.

Q. Could you do that analysis for me? It doesn't have to be today, but ...

A. I don't believe I can.

Q. You can't do that?

A. No.

MR. SNELSON: A. Mr. Rodger, I am not sure whether I misheard your question, but it seemed to me that it was perhaps not -- I didn't understand whether the question was relative to today's gas prices doubling by the year 2000 or whether the gas price in the year 2000 being twice our current forecast of the gas price for the year 2000.

Q. No --

A. But if you look at page 17 of our overheads for this panel, which is Exhibit 320, you

will see that the forecast on which the plan is based is that gas prices will approximately double by the year 2000.

Q. Well, perhaps I might be able to help you along with what I am trying to get at here. If you could turn to page 19 of Exhibit 335.

THE CHAIRMAN: Before we go, another interrogatory was mentioned, 5.9.78?

MR. BROWN: Yes, that is correct.

THE REGISTRAR: 78. I am just checking, Mr. Chairman. That will be 321.38.

---EXHIBIT NO. 321.38: Interrogatory No. 5.9.78.

THE CHAIRMAN: Sorry, Mr. Rodger, what page are we at?

MR. RODGER: I was moving to page 19 of Exhibit 335.

Q. And this is a chart we have taken from Exhibit 143. It is cogeneration sensitivity natural gas price. And what we have done here is we have added a little bit of analysis. What we have done is we have taken an increase of gas by 20 per cent - that is from $2.8 to $3.6, and that reduces the rate of return by 32 per cent.

Do you see where we have made that calculation, Mr. Brown?

MR. BROWN: A. Maybe I can just correct -- the 10.75 should be 10.96.

Q. Okay.

A. That can be read right off the spread sheet. It only changes your number from 32 per cent to 33, so we are in the same ballpark.

Q. Okay. All right. Now, I guess the point I am trying to make: If gas prices went up by 40 per cent, double what we have shown here, and you extrapolate your rate of return line, its going to go right of the scale. The rate of return is going to be zero.

And what I am trying to get at, at what point, when you are looking at a chart like this, at what point does a project no longer become viable because of increases in natural gas prices in real dollars?

A. In our analysis, we assumed 11 per cent would have to be viable for a project to be economic.

If I can refer you to the previous Interrogatory 5.9.78. It actually shows the decrease in cogeneration in the industrial sector versus increases in gas price. And by the price 3.4, which is approximately where you stopped in the 20 per cent, if

that was the new gas forecast, we would have a zero forecast for cogeneration.

Q. Thank you.

DR. CONNELL: May I just follow up on a point from yesterday? I presume the rate of return shown here is after tax as it was in the figure --

MR. BROWN: That is correct.

DR. CONNELL: And can you say offhand whether we are dealing with Class 34 cogeneration here?

MR. BROWN: This is the thermal matching cogeneration which qualifies for Class 34.

I may want to add just one thing: When we talk about increases to the gas price in the bottom, it is relative to that 2.8, which, if you remember my gas price curve, is a starting point of that hockey stick curve. And if we go to say 3.36, as proposed here, that raises the starting price to 3.36 and the curve would run parallel to the graph that was shown on my forecast.

MR. RODGER: Q. Now, if we could please flip back a page to page 18, we are back to Exhibit 3, page 8-5. The heading second full paragraph is "availability and price of natural gas". And that paragraph reads:

The implementation of non-utility

generation projects depends on the availability and price of fuel. Natural gas is particularly important as it is expected to fuel 70 per cent of Ontario's NUG potential in the coming years. The assessment of NUG potential is based on the expectation that natural gas will continue to be readily available and that non-utility generators will continue to be able to contract for it at an acceptable price.

Does this statement still apply to Hydro's position at present?

MR. VYROSTKO: A. That is correct.

Q. I want to confirm one other thing here. We have got a large amount of fuel switching in the commercial and residential sectors to natural gas. We have got 70 per cent of NUGs to be fueled by natural gas.

And I take it that 70 per cent figure is still correct?

MR. BROWN: A. That was the 1989 figure. I am not sure of the 1990 or the preliminary '91 right now. The 70 was based on the '89 analysis.

Q. Would it be fair to say the most

recent figure is higher?

A. That's correct.

Q. We have got Hydro CTUs fueled by natural gas. Let me ask you here as well: Is Hydro considering converting any of its coal or oil-fired stations to natural gas?

MR. SNELSON: A. That has been considered from time to time in one or two places.

Q. Is the Lennox station one of those?

A. Yes.

MR. RODGER: I want to confirm that Hydro's analysis of what new risks the province faces by becoming more and more dependent on natural gas, where is that going to be dealt with, that issue? I know this came up at the last panel.

Mr. Campbell perhaps you could assist me there, please.

MR. B. CAMPBELL: I think some of this, of course, will have to be dealt with in Panel 8, which involves those options. And some of the broader, what I will call, strategic questions that are involved in integrating all the different pieces into a plan will be dealt with in Panels 10, and I expect more importantly, perhaps in Panel 11.

Some of those considerations I expect

will also be touched on in this reintegration of the plan.

MR. RODGER: I am going on to a new issue, Mr. Chairman. Perhaps we could break now.

THE CHAIRMAN: We will break now until 2:30.

THE REGISTRAR: This hearing will adjourn until 2:30.

---Luncheon recess at 12:58 p.m.

---On resuming at 2:36 p.m.

THE REGISTRAR: Come to order. The hearing is again in session. Be seated, please.

MR. B. CAMPBELL: Mr. Chairman, I would just like to record that we have filed the answer to Undertaking 322.7. That was the breakdown of what fit into the different definitions of NUG projects, in-service, committed and proposed projects, and I gather that has been filed.

THE CHAIRMAN: Thank you.

MR. B. CAMPBELL: Sorry, Mr. Chairman, I have been given a set of standing instructions on this matter and they anticipate it has already gone to the Board, and I gather in this case that is not correct.

THE CHAIRMAN: Mr. Rodger?

MR. RODGER: Thank you, Mr. Chairman.

Q. Before the lunch break we were talking about natural gas prices, and I wonder if you could turn to page 20, please, of Exhibit 335, and this is taken from Exhibit 3, page 8-4.

Under the heading entitled "Purchase Rates and Avoided Cost", about halfway down the second paragraph it reads:

> The total cost of the purchase consists of the purchase rate, plus any financial assistance provided, plus any other contract terms that result in actual or potential cost to Hydro. The latter includes items such as the sharing of financial risk associated with potential increases in natural gas supply prices.

I wonder, Panel, if you could describe the nature of this sharing of financial risk associated with gas prices, please.

MR. VYROSTKO: A. This was discussed with a previous Intervenor.

In essence, what we are looking at here is that there is a possibility that, depending on the type of escalation that were to be negotiated with the project, that that escalation would have or could have

cost implications to Hydro by being higher than the standard expected gas prices that we see within our gas forecast, but that the normal expectation of that contract would be that it would be under the natural gas forecast that we have, and, in fact, there would be an equal chance of us being able to gain benefits by the gas being less than the probable.

In other words, the risk that we would take would be in the escalation or the price reopeners, but the risk would be such that there would be as much of a chance of a cost to Hydro as there would be to a savings to Hydro.

Q. So, I take it that sharing of financial risk, that goes to the issue of price of gas only, not to issues of supply, that broader question?

A. That's correct. In essence, all of our gas contracts -- all of the proponent's gas contracts, we look for reserve backing or reserve capability behind all of the assets.

Q. I wonder if you could turn to page 21, please, and this is a notice of the Ontario Energy Board, and it is a notice of public hearing into integrated resource planning. I just wanted to read the purpose of that hearing because it does impact on what we are talking about. It states:

For the purposes of initiating this hearing, "integrated resource planning" is defined as follows: Integrated resource planning for natural gas utilities is an expanded method of planning whereby the expected demand for natural gas services is met from the least costly mix of supply additions, energy conservation, energy efficiency improvements, and load management techniques, i.e. the integration of supply side resources and demand side resources. Some of the specific objectives of the planning process are to continue to provide reliable service, equity among ratepayers and a reasonable return on investment for the utility while addressing environmental issues and achieving lowest cost to the utility and to the consumer.

From that somewhat broad description it is fair to say that there is a lot of overlap in terms of central themes of the IRP hearing and this demand/supply hearing. Would you agree with that?

MR. SNELSON: A. Conceptually there is a

large overlap.

Q. Now, on the next page, page 22, I have just included my understanding that for this proposed hearing there is an initial report done back in the spring of this year, I believe June, and then an updated report which was released September 16th, and that's page 22.

On page 23, I have just included one page of the index from that report just to highlight some of the issues with respect to gas prices.

You will see Roman numeral x, "Interfuel Programs"; down on letter C it's "Fuel Price and Developing Market Considerations for Interfuel Program Design"; D is "Quantifying the Impacts of Interfuel Programs"; Roman numeral xi talks about the financial aspects of integrated resource planning; A is "Collecting Demand Side Program Costs; C is "Impacts of Demand Side Programs on Sales and Revenues"; D is "Utility Financial Incentives".

Have you had a chance to review either of those reports with respect to this hearing?

A. No, I have not.

Q. And I would take it since this is such a very new event that is occurring that certainly the impact of this process hasn't been taken into

account for any of your natural gas forecasting; it's just too early to make that analysis, I suggest. Is that correct, Mr. Brown?

MR. BROWN: A. I guess the gas work, as I can't comment on what factors are used to develop that. You may get more from Panel 8. There was a little bit of evidence in Panel 1 on the gas forecast.

Q. Do you know, though, whether this hearing has been considered as part of your analysis for the long-term forecast?

A. I can't comment on that.

Q. You can't comment on that. Would you agree -- well, maybe this is unfair. Are you familiar with what this hearing is about at all, or is this -- or not really? Would it be unfair?

MR. SNELSON: A. I have a very, very thin general understanding of what this hearing is about.

Q. Your understanding, does it include the fact that part of this hearing is contemplating including external social costs in the price of natural gas?

A. I wasn't aware that that was a specific proposal.

Q. Can you advise me whether Ontario

Hydro is going to be an intervenor at this hearing?

A. I know it has been considered. I don't know what decision has been made on that.

Q. Would you agree with me that -- I don't know whether you can or not, but we are on the verge here of some very, very significant planning changes of how we view and how energy is going to be consumed in this province in terms of this hearing.

And now with this gas integrated resource planning it could have very, very profound impacts on natural gas and natural gas prices.

Would you agree that this hearing proposed before the Energy Board, it's a great uncertainty as to what impact that is going to have, but it will, or it could at least, be very, very significant in terms of things like long-term gas prices?

MR. B. CAMPBELL: Mr. Chairman, those are interesting submissions, but, with respect, I don't in my submission see that they are a fair question to this Panel who have basically said that they have only the most rudimentary knowledge of the process that is being followed there, and clearly in terms of preparing for their responsibilities for this hearing that is quite understandable.

In my submission, that is simply not a fair question. It's more in the nature of a submission.

MR. RODGER: Q. Perhaps I could ask, Mr. Brown, are you going to be looking at the latest draft report for the IRP hearing when you are preparing your next NUG plan from the context of natural gas prices?

MR. BROWN: A. My NUG forecast is based on the most recent gas forecasts I have, and that is produced by our economics and forecast division, and that forecast was provided in Exhibit 320, page 17, the graph of it, and that is as far as we have on that. It would be doubtful whether this is in it, but I can't comment on that.

Q. Now, at the commencement of the proceedings this morning Dr. Connell had a few questions about gas contracts which I had also intended to ask about.

Let me just confirm, did I hear your evidence this morning that Ontario Hydro insists that independent power producers enter into these long-term contracts with gas utilities? Did I hear that right?

A. As part of our contract requirements they get 15 -- well, the contract term minus five years.

Q. Sorry, the contract...?

A. The contract term, the power purchase contract term less five years, which the typical contract is twenty years so we would insist on a fifteen year gas contract.

Q. Is that the longest contractual period, fifteen years, that a NUG has with a gas utility, or can they go longer?

MR. VYROSTKO: A. We have longer contracts.

Q. What's the longest one?

A. I believe it's twenty years.

Q. Okay. Thank you. I would like to move on to a new area, and that is the dispatchability of NUGs. If you could please turn to page 1 of Exhibit 335, back once again to the chairman's speech to IPPSO, and the fifth paragraph states:

> Non-utility generation projects are not only becoming more numerous, they are getting larger. Therefore, it is becoming increasingly necessary to ensure that these units provide the same operating flexibility as our own units. Like Hydro's own generating units, NUG units must respond to system needs.

Now, Mr. Snelson, the issue of dispatchability came up in your direct testimony, and I believe it was your evidence when you said that one of the important aspects of dispatching is to reduce the cost by making preferential use of low cost fuels; is that right?

MR. SNELSON: A. That is correct.

Q. And you also said that NUGs should contribute their share to the need for a flexible system operation that is appropriate to the technology that is being used. Do you recall saying that?

A. I recall that statement, too.

Q. I take it that the reason why this is important is that Hydro wants to achieve the most efficient and cost-effective way to use the resources that is available to it. That is what dispatchability is all about, isn't it?

A. Yes. I think it is also about making the most efficient use of resources overall.

Q. Okay. I wonder if you could go to page 24, please, of Exhibit 335, and this was AMPCO Interrogatory 4.24.30.

THE REGISTRAR: That is number 321.39.

---EXHIBIT NO. 321.39: Interrogatory No. 4.24.30.

MR. RODGER: Q. Perhaps I could describe

this interrogatory and the response by saying that the response involved running a simulation study on Hydro's LMSTM model, and the result showed the resource mix on the margin given a 200 megawatt increase in system demand for the whole year of the period 1989 to 2008.

Now, the resource mix itself is shown in Part 3 of Table 1 of the response, and that is on page 28 of my exhibit, and about halfway down the page is Part 3, "Estimate of Additional Electricity From Nuclear Sources", and Table 1 is given there.

And for the sources there are three types: nuclear sources, coal, and gas and oil.

Now, if you turn over to the next page what I have done is blown up part of that chart to make it more readable. Would I be correct, Panel, when I say that nuclear generation is on the margin close to 58 per cent of the time in 2004 and even more of the time in the immediately ensuing years?

MR. SNELSON: A. No, I don't believe so.

Q. And why is that incorrect?

A. If you were to look at Figure 16-7 of Exhibit 3, then --

THE CHAIRMAN: Just a moment.

MR. SNELSON: That is Figure 16-3 on page 16-7.

If you have that, the centre figure on the lefthand side, which has a small heading "Annual", and that shows, as a bar chart, the proportions of time that nuclear, coal, and oil and gas are the marginal fuels by year, and you can see that in most years nuclear is on the margin for less than 20 per cent of the time.

MR. RODGER: Q. Perhaps you could tell me what the response in this chart that I am pointing out to you, page 29 of Exhibit 335, what do those percentages mean, then?

MR. SNELSON: A. Okay. I believe -- and I haven't been back thoroughly and reviewed this, but I believe that having read the interrogatory and the answer that the people who prepared this interrogatory answered your question as to what would be the effect of substituting electrical ground source heat pumps for natural gas space heating or oil space heating in terms of carbon dioxide emissions, and they would have had to look at two effects.

One is that if the demand for electricity has gone up because there is more heating in these electrical forms, then that would affect the amount of capacity that we build and so they would have to reflect into that calculation that more capacity would

be required because of the additional electricity demand.

Now, assuming that the capacity that is built to meet that demand is a mix of nuclear and gas-fired generation, then quite a large part of that capacity that is built has the capability of supplying a large part of that energy from additional nuclear capacity.

[2:55 p.m.]

And so the calculation here would be for a long-term change to the electricity demand including changes to the capacity.

The marginal energy fuel - and we started a discussion about dispatching - the marginal energy on a day-by-day basis and the dispatching decisions are made with a fixed amount of capacity, assuming that the capacity doesn't change.

So, given that you have a fixed amount of capacity in any one year and that most of -- if the system is well designed, the nuclear capacity is going to be fully utilized most of the time, then the proportion of time that nuclear would be on the margin would be very small.

So, this is really, I think, the difference in economists' terms between short-run

marginal cost and long-run marginal cost. The short-run marginal cost assumes changes with no change in capacity; and long-run marginal cost assumes that the capacity can change. And I think that is the essential difference between those two sources of information.

Q. Could you tell me, Mr. Snelson, you say for the year 2004, it is just over 20 per cent of that nuclear is on the margin.

How about from 2004 to the end of that decade, what would be the highest percentage that nuclear would be on the margin?

A. Well, this is based upon Plan 15 as it was predicted to be at the time the Demand/Supply Plan was prepared. And again, going to Figure 16-3, page 16-7 of Exhibit 3, then you can see from that figure that the last two years of the plan, the nuclear is on the margin close to 30 per cent of the time.

Q. All right. That is helpful in helping to interpret that.

I wonder if you could turn to page 31, please, and this is from Exhibit 44, Table 9.1. And the table is the future station levelized unit energy costs in 1988 cents per kilowatthour.

And the third column of information is

entitled "fueling". And the total fueling figure, and that is the bottom column to the left, the bottom row, is .354 cents a kilowatthour, just above the total LUEC figure.

Do you have that, Mr. Snelson?

A. Yes, I see a figure for existing site of .502 and -- sorry, I see a figure of .354 on a system expansion basis.

Q. Yes.

A. And .502 on a direct and allocated basis.

Q. Okay. And I wonder if you could turn over the page, page 32, and this is from Exhibit 320, and page 16. This is the 1990 cogeneration model assumptions. And we see for 1995, the buy-back rate is 4.23 cents a kilowatthour.

Now, although my quote from Exhibit 44 is in 1988 dollars, would you agree that the nuclear fuel cost is roughly comparable? It may be up to maybe .5 cents a kilowatthour for 1990, but it is not going to be a huge difference.

A. Comparable to what, I am sorry?

Q. To the 88 cents per kilowatthour figure?

A. Well, if it just goes up at inflation

rate, it would go at about 5 per cent per year.

Q. All right.

THE CHAIRMAN: I am sorry, what figure are you looking at in the chart to compare it to, please?

MR. RODGER: In --

THE CHAIRMAN: You are comparing the 4.23 cents per kilowatthour to what figure, which one?

MR. RODGER: That was my initial figure that we looked at, Mr. Chairman, the .35 cents per kilowatthour, the total fueling.

THE CHAIRMAN: All right.

MR. RODGER: Q. And just with that comparison of the .35 cents to the 4.23 cents, let me just describe the concern that we have with respect to dispatchability and this is why I asked you about how much of the time nuclear was on the margin.

The situation is that the dispatcher at Hydro, he is looking out on to the next week and he is trying to determine how much electricity the province needs and it is at a time when nuclear is on the margin about 30 per cent of the time.

Our concern is that if Hydro has to buy the power from the non-utility generator, then it is going to be incurring financial losses because it is

bound to buy the higher priced fuel, the higher priced power from the NUGs as opposed to just running the nuclear; is that clear? Is that concern clear?

MR. SNELSON: A. I think I understand your concern. I would like to clear up a point about your comparison, though, and that is that the 4.23 cents per kilowatthour that is shown on Exhibit 320 is, I believe, an estimate of the rate that we would pay for non-utility generated electricity, including components that are intended to compensate the non-utility generator for his fixed cost.

So you are comparing the variable costs of nuclear generation with the fixed costs of a non-utility generator; however, given that difference, you are still going to see a large difference between the incremental fueling cost of a gas-fired non-utility generator, particularly if it is a non-utility generator that is primarily there to generate electricity and has a small component of cogeneration.

So, if it is either a major supply non-utility generator or one of these overbuilt -- sorry, a major supply combined cycle with no cogeneration or it is an overbuilt cogenerator, then the incremental cost is going to be quite high.

And our intent particularly with those is

to seek terms and conditions that would allow us to have the economies of dispatching them.

Q. And to be fair with respect to this comparison of the figures I pointed out earlier, by the time that nuclear is coming on the margin though, your capital costs are already sunk by that time?

A. Yes, but in fairness to the non-utility generator, he has sunk his capital costs, too.

Q. All right. I guess to expand the concern, if Hydro has a choice and it can get power from its nuclear sources on the margin and it can do that cheaper or it can go and buy from the non-utility generator, which would be the higher cost given this scenario, which choice does Hydro make?

A. There are choices made at different times. There is the choice made at the time a decision is being made to build a nuclear plant or any other plant by Ontario Hydro and the decisions that are being made at the time that we sign a contract with a non-utility generator so that he can build his plant.

In those cases, the proper comparison in looking at those things is to look at the total cost, including capital charges, operating costs over the lifetime of the facility of the non-utility generation

as compared to the cost of Ontario Hydro doing it which will reflect in avoided cost. So at that time frame, you have to look at the totality of the costs.

When you are coming to making an operating decision and you are into the week ahead type of time frame, then you have to look at the incremental situation, which is largely variable cost, which will have to take into account contractual provisions that have been undertaken with non-utility generators.

Now, we often have in our non-utility generation contracts a clause that does allow some curtailment during hours of surplus base load generation. That is when hydraulic generation or nuclear generation is the marginal fuel. And so we do have some limited contractual ability to cut back in those circumstances.

Q. Those arrangements, are they in place with every NUG? Is that part of your standard contractual provisions?

MR. VYROSTKO: A. We have been placing these types of arrangements into all of the new non-utility generation projects we have been negotiating for, I would say, in the last year. So typically, they would include all the larger ones that we have been referring to, yes.

Q. Just one last point along that line. Within these provisions of the contracts, how much flexibility do you have? Is it one set period of time for a NUG or does it change from project to project?

A. It would change from project to project, but the principle we are trying to achieve is, as Mr. Snelson said, to give us some limited ability to, in fact, dispatch or curtail because it is not fully dispatchable so we call it curtailment, that we can, in fact, ask the generator to shut down when, in fact, we have a nuclear run margin. And typically, that would be in the summer off-peak periods.

Q. If I can summarize Mr. Snelson's evidence with respect to this point: Is Hydro's position that they are looking at the overall picture, right, from the NUGs' first capital costs right to their fuel costs and in terms of nuclear, from all the nuclear capital costs and fuel costs, and that is how the analysis is done?

MR. SNELSON: A. That is how the analysis is done as to what sort of generation to build and what sort of long-term contracts to sign. By getting a better match between the operation of a NUG and the system need in the contract, you may, in fact, end up with a better arrangement and better deal than

just one with no dispatching at all.

Q. Has that analysis been provided in any of the evidence to date?

A. I am sorry, what analysis?

Q. That you just talked about, looking at the overall picture with respect to nuclear costs and the overall picture with respect to NUGs and see how the NUGs compared with the nuclear in this situation of new nuclear coming on in the margin?

A. No. It is dealt with at the moment through the avoided cost process, which we have described.

Q. All right. I wonder if you could turn now to page 33, please, of Exhibit 335, and this is taken from Exhibit 143 and under the Section 2.1.1, industrial sector. If you go down to the fifth paragraph, I just want to read the first couple of sentences.

"The majority of Leighton & Kidd sites that are now NUG projects, either in service or committed, had steam capacity factors in excess of 70 per cent. The 70 per cent plus SCF group is also significant from an economic analysis standpoint. Based on an economic spread

sheet analysis, projects should run at over 70 per cent capacity factors in order to achieve a pre-financing after-tax rate of return of 11 per cent. After financing is accounted for, it is assumed that these projects would achieve a 15 to 25 per cent after-tax rate of return."

I am wondering if you could tell me what type of financing and range of interest rates were assumed in making this statement.

MR. BROWN: A. The determination of the 11 per cent was based on a range of debt percentages which we are undertaking to provide but is based on a 12 per cent interest rate, fifteen year term.

And there is an undertaking that will show the changes in after-tax financing with changes in debt percentage and that should be available shortly.

MR. RODGER: If I could get a copy of that undertaking as well, please, Mr. Campbell.

MR. B. CAMPBELL: Okay.

THE CHAIRMAN: No, it is not a separate undertaking, I don't think.

MR. BROWN: That is an existing undertaking, that's correct, yes.

MR. RODGER: Yes. I would just like to get a copy of it please.

THE CHAIRMAN: I think they are generally distributed, aren't they?

MR. RODGER: They are just given to the person who asked for it.

MR. B. CAMPBELL: The procedure that has been followed, as I understand it, and this is vague at best, is that it is provided to the Board, it is provided to the party that requested it and I announce it so that people who have an interest in it can come and ask me for it if they need it, but we don't send all the paper to everybody on the specific intervenor's undertaking.

THE CHAIRMAN: Is that okay, Mr. Rodger?

MR. RODGER: That is fine, Mr. Chairman.

Q. Now, I wonder if you could now turn, keeping that quote in mind that I just read, to page 34 and 35 which are both from Exhibit 320, pages 14 and 15 respectively.

And page 14 shows a typical combined-cycle generator that will have an efficiency substantially less than a typical high-efficiency cogenerator. And we see at the bottom right-hand corner of each page, we have 43 per cent as compared to

57 per cent.

Now, given Hydro's evidence that cogen needs to operate at over 70 per cent capacity factor to produce a prefinancing rate of return at 11 per cent, could you tell me what capacity factor must a gas-fired major supply NUG enjoy to meet that same 11 per cent rate of return?

MR. BROWN: A. The analysis at 11 per cent rate of return and the 70 per cent was done in the 1990 NUG plan. At that time, zero megawatts of major supply were deemed to be viable under that scenario.

Q. And will that be the same for the '91 plan?

A. We are studying what the per cent will be. Obviously, a major supply is zero per cent capacity factor. We will not be forecasting that in the '91 plan, only taking those that are committed. And there is a committed project as we have already shown in the previous undertaking.

Q. I have one point of clarification regarding the Class 34. I believe it was Mr. Vyrostko's evidence when he said that some projects no longer require the Class 34 accelerated depreciation to be viable.

That is correct, Mr. Vyrostko?

MR. VYROSTKO: A. I believe that the one project, the major supply NUG, which, from what I understand, would not qualify for Class 34 obviously doesn't need it to make it viable if it has now signed an agreement with us.

Q. Okay. I wonder if you could turn to page 36, please, of Exhibit 335, and this is Interrogatory 5.24.18.

[3:15 p.m.]

Could we have a number, please?

THE REGISTRAR: Yes. 321.40.

---EXHIBIT NO. 321.40: Interrogatory No. 5.24.18.

MR. RODGER: Q. If you go down to the last paragraph of the response, Hydro says:

> Yes, the use of Class 34 does affect the viability. Hydro studies indicate that without Class 34 cogeneration is not viable.

Now, this interrogatory was answered in I guess that's the end of May, '91. Could you tell me what has changed since May which might make cogeneration now viable without the Class 34, or does that just -- was your answer just restricted to major supply NUGs?

MR. VYROSTKO: A. My answer that I gave

just previously was an example, an example of a specific combined cycle of a major supply NUG that in fact became viable.

Class 34 is still a significant factor in the viability, and what has changed really from that period to now is there is gas pricing, and the fact that gas has been able to overcome the -- that benefit that Class 34 brings.

Q. So the answer to this interrogatory that without Class 34 cogeneration is not viable, that still holds true today?

A. No.

Q. Because I hear your evidence as being that for the major supply NUGs they might be able to get by without the Class 34, but for cogen it might be a different story.

A. I think even for cogen it could be viable with natural gas prices the way they are.

Q. Okay. Now, I know Mr. Campbell just recently handed out the answer to Undertaking 322.7. This is Hydro undertaking to provide a breakdown of the in-service, committed and proposed projects which Mr. Shepherd asked about.

Now, I was also going to ask that. I wonder if I could add one more request to that

undertaking, and that is, Hydro identify the locations of those projects by Hydro region.

MR. BROWN: A. The in-service and committed, you probably have a list of that, every one of those sites, site by site. I assume you are only talking about the proposed projects.

Q. Actually, both if we could get it. It doesn't have to be today, but if I could get that added to this undertaking it would be appreciated.

A. The in-service list has been provided in a previous interrogatory which has in-service and committed. It may be easier if I just attach that list to the undertaking, and I think I can agree to provide a regional breakdown of this.

It may take me a while, that's all. We can do that.

MR. RODGER: Thank you. Should we get a new undertaking number for that, Mr. Chairman?

THE CHAIRMAN: Do you want just the 58 and the 15 broken -- and 43 broken out, or do you want them by each technology?

MR. RODGER: By each type of non-utility generation.

THE CHAIRMAN: All right, that's number -- new undertaking number...?

THE REGISTRAR: 322.18.

---UNDERTAKING NO. 322.18: Ontario Hydro undertakes to give a regional breakdown of each type of non-utility generation.

THE CHAIRMAN: I take it you can't reconcile or do you need to reconcile or is it even appropriate to reconcile these figures here with 331B?

MR. BROWN: That was -- if I remember correctly, it was just the forecast and the rate offers, and those rate offers are included in the "proposed" category.

THE CHAIRMAN: But there would be others as well?

MR. BROWN: Yes. I will provide a regional list under each one of these technologies for the proposed projects and attach our in-service and committed list to that.

MR. RODGER: Q. All right. Thank you.

Now, earlier in your direct evidence you described how independent power producers can build smaller NUGs cheaper and faster than Ontario Hydro, and you went into the reasons for that.

I wonder if you could advise me, at what size project and what type of generation, at what point does it become no longer economic from Hydro's point of view to let an independent power producer build that?

What's the threshold of Hydro saying, we are better off and the ratepayers are better off if we build that plant?

Is it 200 megawatts, 500 megawatts? What's the threshold?

MR. VYROSTKO: A. I don't think we have any information that would give us a threshold with respect to size.

Q. Well, perhaps I could ask, then, would Hydro ever consider itself building a 50 megawatt cogenerator? I know it has talked about building CTUs, but if there is no threshold why doesn't Hydro build a 10 or 20 megawatt plant?

A. I think Mr. Snelson made reference to that in his direct evidence where it would be very difficult for Ontario Hydro to go in on an existing customer's property and install a facility that uses part of the facilities there for themselves for electricity production while at the same time the industrial customer is using the steam for himself.

Q. But surely, Mr. Vyrostko, there must be some point that Hydro says, you know, we have done this for a long, long time; we can do it cheaper than anybody else?

A. I believe that Ontario Hydro has

looked at a number of options for supplying electricity in the province, and what we have found is that there are some that make sense for us to do and there are others that make sense for the private sector to do.

And right now we believe that cogeneration, which is really dealing with the industrial sector, makes more sense for the private sector to do.

THE CHAIRMAN: So you wouldn't play the role of the third party developer in any...is that right?

MR. VYROSTKO: We are not anticipating to do that, no.

MR. RODGER: Q. Mr. Vyrostko, perhaps if I could leave aside the cogeneration, and let's say we are just talking about the straight electricity-producing units. Surely you must then have a threshold point, you know, when it is cheaper for Hydro to build it rather than letting the private sector build it.

MR. VYROSTKO: A. Again, I can't say that you can make that threshold based on size.

Clearly, the important threshold we use is avoided cost, and if Hydro has an option that they can bring in at or below avoided cost then that would be the option we would be looking at, and there are a

number of projects that the private sector can't bring in at avoided cost.

MR. RODGER: I am coming to my last series of questions. I think I can finish before the break.

Q. Now, I take it, as we talked about earlier, before lunchtime, the lead time for major supply NUGs at this stage is the same for a smaller cogen, and that's three years; is that correct?

MR. VYROSTKO: A. I haven't said that necessarily is the same lead time. What we are saying is that typically after the contract has been signed we have found to date that the projects take between two to three years to get constructed and placed into service.

Q. We know from Panel 2 that the lead times for Hydro CTUs are roughly 4.5 to six years; isn't that correct, Mr. Snelson? I think actually this morning you said five to six years.

MR. SNELSON: A. I didn't realize that I had given an estimate this morning. We have a table in Exhibit 3, and I am just looking for it.

MR. B. CAMPBELL: I believe Mr. Snelson's comparison he was asked about this morning was with respect to transmission.

MR. RODGER: That's correct.

Q. Perhaps you could just tell me then, what's the lead time, current lead time for a CTU?

MR. SNELSON: A. The lead time that is given in Exhibit 3 - and I am at page 15-6 -- Figure 15-6 - shows an acquisition time of one to two years for combustion turbine units and three to five years for combined-cycle units.

And acquisition time is from the time that you decide to proceed, having got all your approvals, to having the plant in service, and perhaps that is the most comparable lead time to the time that Mr. Vyrostko mentioned from signing the contract with a non-utility generator to having it in service.

Q. Okay. With that, I just want to see if I understand a couple of the differences between the 1990 and the 1991 NUG plan.

We have now got an additional 1,000 megawatts of viable major supply NUGs to be committed by year end for the year 2000, but in the 1990 -- 1991 NUG plan Hydro is not going to try and forecast major supply NUG. As Hydro needs this technology, the NUG division will solicit NUG proposals; is that correct?

MR. VYROSTKO: A. That's correct.

Q. And as commitments are made to major

supply NUG, then they will be incorporated into the NUG plan at that time; is that correct?

A. That's correct.

Q. I wonder if we could finally look to page 37, and this is from Volume 60, page 10719. This was a cross-examination of the Demand Management Panel, and at line 14, the questions were asked of Ms. Fraser about targets, and Ms. Fraser answered:

"I would also point out that we are not going to wait until the year 2000 to find out whether we have achieved a target or not."

And the general discussion was that demand management targets, for example, were being evaluated constantly and the plan would change accordingly.

Now, if you go over to page 38, which is also from Volume 60, lines 1 to 7, Mr. Shalaby states:

Page 15-68 has a discussion about flexibility, and it really sums up what Mr. Burke was saying. If you have a plan that's flexible enough to respond to upper load growth it will be flexible enough to respond to shortfalls in demand management, provided you don't get hit

with both upper load growth and low yield in demand management.

Now, I want you to imagine that Mr. Shalaby's analysis there becomes reality; you have upper load growth and low yield in demand management.

In the case of the lead times that we are talking about for major supply NUGs, if Mr. Shalaby's case becomes reality doesn't that mean that your division is going to have to make decisions about major supply NUG in the next two or three years to ensure that we are not going to have a shortfall in electricity supply by the end of the decade?

A. One of the things that we learned from our request for proposal was that from the time when we received a proposal to a request to the time the project is in service takes approximately four years, and, in fact, the responses that we are getting are that most of those projects will be in service by 1994.

That is telling us that the industry can respond to a request that we have in a four year time period. Therefore, if your scenario saying that the year 2000 we will be short, then we have until 1996 or thereabouts, provided everything stays the way it is now, to wait and then make a request from the industry.

Q. So we are looking then the mid-'90s, '95/96? That's when these decisions are going to have to start to be made?

A. They may, in fact, be made even earlier, depending on how we see the activities taking place as of today and with our new way of looking at high efficient cogen, but I guess what I am saying is I have from now until about '94/95 to decide whether in fact we have to do something in addition to that to meet the needs of the system.

MR. SNELSON: A. I would just like to add that one factor of the reserve margin calculation of what is an acceptable reserve margin to plan on does allow for a number of years of lead time between a load forecast deviation starting to happen and it being responded to.

So if you can't respond immediately to a change, then it tends to eat into the reserve margin, and that's partly what the planning reserve margin is there for.

Q. Perhaps I could ask you, Mr. Vyrostko, if it looks like Ontario is approaching shortfalls in electricity supply would Hydro then increase the premium for NUGs to try and get some more on stream quicker?

MR. VYROSTKO: A. Again, I think that that is a question that has to be asked as we approach that situation. There may be other factors that could in fact be brought on stream for assisting the system for that period of time, especially if it is a short-term situation only.

I think the issue, though, is that as we move forward in time we really have to stay on top of all of the elements in the overall balance between system demand and system supply and ensure that we have got enough flexibility to respond when in fact it's necessary.

MR. RODGER: Those are all my questions. Thank you, Panel. Thank you, Mr. Chairman.

THE CHAIRMAN: Mr. Greenspoon, you are ready to go next after the break?

MR. GREENSPOON: Yes, sir.

THE CHAIRMAN: We will adjourn for 15 minutes.

THE REGISTRAR: The hearing will adjourn for 15 minutes.

---Recess at 3:34 p.m.

---On resuming at 3:50 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

Q. So, what do you say about the future then with regard to this 70 per cent figure that we have as of April 1st?

A. I haven't got the number in front of me, but I know we did do that for cogeneration and northeastern and northwestern represent about 50 per cent of the cogeneration that we expected to be attainable by the year 2000.

Q. What does it represent in terms of hydraulic?

A. That information I don't have.

Q. It would be even higher than 70 per cent, wouldn't it?

A. Most of the rivers are in Northern Ontario, that's correct.

Q. So, you have no reason to think that it would be any different in the future? In fact, given the trend, it's likely to be at least as high or higher in the future?

A. I think that's accurate for the 1990 NUG plan and the numbers in the 1990 plan, but I don't think it's accurate for the 1991 plan and we are still working on that.

Q. All right.

THE CHAIRMAN: Just a moment. You have

THE CHAIRMAN: Mr. Greenspoon?

MR. GREENSPOON: Thank you, sir.

CROSS-EXAMINATION BY MR. GREENSPOON:

Q. Panel, you heard me say earlier on when I was making submissions about something before this panel started about the amount of NUGs that Ontario Hydro gets from Northern Ontario, and I put it to the Panel that it was 70 per cent. Do you agree with that statement?

THE CHAIRMAN: That would be for the northeast and northwest region, is that what you are talking about?

MR. GREENSPOON: Yes. When I say Northern Ontario, I mean northeast and northwest in terms of Hydro's regionalization of the province.

Q. Do you want me to tell you where that's found? Interrogatory 5.6.38.

I didn't think it would be necessary. That interrogatory is about 4 inches thick and I didn't want to have to reproduce it.

THE REGISTRAR: That's 321.41.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 321.41: Interrogatory No. 5.6.38.

MR. VYROSTKO: Yes. The interrogatory says 70 per cent.

MR. GREENSPOON: Q. Yes. So is it probably true? (laughter)

You didn't seem to know. Maybe it was just because I used an exact figure.

MR. VYROSTKO: A. Well, I think that the interrogatory here refers to April 1st, as of that date. So as of today I am not sure what that number would be.

Q. I wanted to ask you, off the top of your head, having seen this, pretend you didn't see it, what would you have said? You would have said, I take it, that it would have been a high percentage?

A. Yes, I would.

Q. Is it fair to say that it is likely to continue that way?

A. There are a number of developments in the north, that's correct.

Q. And it's likely to continue in the high 70 per cent, give or take a few per cent?

A. I can't say that. Over the long-term I can't say that.

Q. What can you say, Mr. Brown, in terms of your forecasting, or is that important to you?

MR. BROWN: A. I try and estimate the regional distribution of future NUGs.

given some thought to how the 1991 NUG plan may work out, I realize you are not committed to it, but do you see any shift in that trend in the 1991 plan?

MR. BROWN: I do in terms of some of the proposals that I accepted rate offers, there is not that 70 per cent in those.

THE CHAIRMAN: Or even the 50 per cent?

MR. BROWN: The 50 per cent in the cogeneration I think is still acceptable.

MR. GREENSPOON: Q. Just following up on the Chairman's question, it may be the major supply NUGs that are going to be different. There may be more major supply NUGs in the south that might tip the balance down from 70 per cent; would that be a fair..

MR. BROWN: A. I was including all rate offers accepted which is these non-preferred co-generators, as well as major supply.

Q. Right. So, the preferred will certainly be in the north.

A. I think that would be a better representation of the 70 per cent. That would be the remaining preferred.

Q. In any event, it's going to be a high number in the north. Can we agree on something?

A. Yes, it would be a significant

portion of the plan.

Q. All right. Now, I divided non-utility generation into three categories, and I rated them, and I am just wondering, I will put the rating to you and I just wonder if you will agree with it, from your direct evidence, that the best -- and I realize using a value judgment maybe is not right, but just for the purposes this question, I will put it to you that the best type of NUG is a load displacement cogeneration, the second best is just straight cogeneration that doesn't displace load, and the third best is a non-cogenerative NUG or I guess what we would call a major supply NUG. I guess when I use the word "best" what I am talking about is in terms of the environment. After all, this is an environmental assessment. And in terms of impact on the environment and on the system, I am wondering if you agree with that ranking.

A. I think your question is just referring to cogeneration and not other NUG technologies, is that correct, like small hydro or wood waste?

Q. I'm certainly not talking about small hydro when I ask this question, no.

A. My initial response would be that

there would be very little difference in terms of environmental impacts between the first two classifications. I don't think the purchase or load displacement changes the environment. That's essentially where you are putting the meter on that generator, it's the same facility, just a different owner. I am assuming they are both high-efficiency cogenerators.

Q. So, you are saying that you agree that the third one is not attractive as the first two to the environment, but you don't agree on the difference between the first two?

A. The first two are our preferred options.

Q. But there is a difference, an impact on the environment if there is a need for new transmission, isn't there, and we don't need new transmission for load displacement cogeneration, at least not to the same extent; isn't that true?

MR. SNELSON: A. It's hard to generalize.

THE CHAIRMAN: You mean you might need new transmission on a load displacement?

MR. SNELSON: There is regard to the transmission line that goes into the plant that is

producing the electricity, then a load displacement cogenerator that reduces the load of that plant, reduces the need and the amount of transmission needed for that particular case, so you wouldn't have to upgrade that transmission line. But when you go back into the system, then a load displacement cogenerator can affect the system balance on an inter-regional basis, the same as a purchase cogenerator. And if the purchase cogenerator was to be a third party purchase in a plant as Mr. Brown has said, if it was to be a third party cogenerator who was selling steam to a plant and electricity to Ontario Hydro, then the effect on the transmission line to the plant might be the same too.

MR. GREENSPOON: Q. But, but in just a hypothetical example, if I was using 2 megawatts at my plant, and I was producing 2 megawatts at my plant, that wouldn't have any impact on the transmission of the system at all, but if I was not using any electricity but was producing 2 megawatts, it might change the system if there was a bottleneck between the inter-regional system?

MR. SNELSON: A. It's very difficult to generalize. In a hypothetical example you can construct hypothetical examples where there are

transmission savings.

Q. Has Hydro given a priority? Assuming that for this next question, that I am right and that there is an advantage to load displacement cogeneration over straight cogeneration, and maybe we will review that or revisit that issue in direct, in our direct, but has Hydro -- and you seem to be giving a qualified partial positive answer to that, Mr. Snelson. Assuming that there is an advantage, has Hydro given a priority to these kinds of NUGs? In contract negotiations has Hydro shown an interest in giving priority to a producer who not only cogenerates but displaces his own load?

MR. VYROSTKO: A. I think first of all, any producer that is looking at load displacement would be an existing customer of Ontario Hydro or the utility, and we would be very, very interested in doing whatever we can to help that customer do whatever is necessary to become energy efficient and become competitive, not only within the province but globally, and therefore, if cogeneration was an element of that competitiveness, we would do all that we can to help them with the cogeneration project.

So, from the perspective of a load displacement cogenerator who is a typical customer of

ours, then our regional representatives and ourselves would be working with that customer to in fact help him look at cogeneration.

Q. So, would you go so far as to examine potential? I know you have said on your direct that you don't go out seeking cogeneration, but I guess my question is, why wouldn't you look where a lot of heat is being used, maybe going up a stack, and where there is a lot of load being used by the customer and priorize those particular industries as candidates for load displacement cogeneration?

A. I think partly that is done. On the one hand, with the non-utility generation plan we look at all the steam users. So, from that perspective we are looking at those people who have opportunities for taking advantage of the heat or the steam created and we then try to identify which ones we think are going to occur and happen through the forecast.

Our regional representatives are always out there dealing with customers and trying to help them with their overall business. So therefore, if any of our regional representatives sees an opportunity where there is waste heat and it's not being recovered in any way, they would clearly identify an opportunity for cogeneration.

Q. But you are not giving that a priority in terms of contract of rates or anything like that?

A. Well, I think, first of all, we do through the preference adder, a high efficiency...

Q. I'm sorry through the...?

A. We provide what we call a preference adder.

Q. Preference adder, okay.

A. A premium up to 10 per cent for high efficiency cogen projects. So, from that perspective we do that.

Q. But you, as Mr. Brown said, put my first two first categories together in that regard.

A. The purchase and the load displacement in that category would be -- could be the same if they are thermally balanced.

Q. So, you don't care whether there is load displacement in terms of contract negotiation?

A. No, that's right. Our focus is on the cogeneration portion which is really the overall application of energy and the use of energy on that site.

The other thing though that we have to help with these is we have a consulting study

assistance program where in fact we would pick up half the cost of the consultant study to help identify an opportunity with a customer on cogeneration.

Q. Okay. Did you want to add something?

MR. SNELSON: A. The only point that perhaps is worth adding is that the specific transmission costs of connecting a purchase or load displacement non-utility generator, but usually the purchase type to the system, is charged as a cost to the non-utility generator. So, in that sense, the specific effect is reflected in the --

Q. Yes, I think you knew that I meant when I raised the issue of transmission I was talking the system rather than the connection.

A. As regards the system --

Q. The bottleneck is what I was talking about.

A. As regards the system and not the connection, then load displacement NUGs and purchase NUGs are usually the same.

Q. In terms of contract negotiations and rates?

[4:08 p.m.]

A. No, in terms of their effect on the system. When you go back from the specific connection

to a broader area, then load displacement NUGs and purchase NUGs are usually the same in terms of their system effects.

Q. But you agreed that -- I mean, I don't want to ask these questions too many times, but you did agree with my hypothetical that --

A. I agreed that you could construct a case where that was so.

Q. Right, right. And especially in northern Ontario, where you have said in your direct evidence that we have transmission bottlenecks.

A. Transmission bottlenecks in northern Ontario for inter-regional flows--

Q. Right.

A. --will be the same whether the cogeneration that is connected to the system is purchase or load displacement.

Q. Well, how can that be when the one is putting electricity into the system and the other isn't doing anything to the system?

A. It is reducing the load of the system and that has -- let's say that we have an area that has a certain amount of load and a certain amount of generation and that the generation exceeds the load, so there is a flow out of the area, then if you have an

increase in the generation because you have a purchase non-utility generator, then that increases the flow out of the area.

If you have a reduction in load because you have a load displacement non-utility generator, then that also increases the surplus of generation in the area and has the same effect in terms of the flow out of that area.

Q. Yes, but if you do both at the same time?

A. What do you mean by both?

Q. Well, if you have a 2 megawatt user and a 2 megawatt load displacer.

A. A load displacement non-utility generation is usually the displacing of an existing load. And the assumption normally is that if he didn't cogenerate, then his total load would be the same and that the load displacement cogeneration has the effect of reducing his net load on Ontario Hydro.

Q. But if the system is self-sufficient, which I gather we are in northern Ontario -- in fact, we are a net exporter of electricity in northern Ontario if you count the non-utility generation.

A. I am not sure that is the case.

Q. All right. Well, we are close.

Let's, for argument sake, say we are self-sufficient.

A. I believe at the moment the situation is that you are a net exporter during the daytime and a net importer at night.

Q. It has to do with peak, yes.

A. And you are a net importer at night.

Q. All right. So let's say that at one given time, there is nothing happening. There's nothing coming into northern Ontario and nothing going out of northern Ontario; that we are using up all the electricity that we are making.

If we put a load displacing NUG on that system, it will have no impact on that system except to reduce the load.

A. Is your hypothesis that the transmission between northern and southern Ontario is either not in use or just floating and no flow on it?

Q. Right.

A. And if you put a load displacement non-utility generator in northern Ontario, it will create a flow into northern Ontario?

Q. That's right -- no, it would reduce the load -- yes, it would create a flow.

I guess in my hypothesis we have cut off the line between Toronto and Sudbury, not that I am

suggesting we should do that. But what I am saying is, just in theory - and I know you have a complicated system, but I have to put this down in terms that I can understand - if we displace 2 megawatts of load, then there is 2 megawatts freed up for somebody else to use in northern Ontario?

A. That is correct, and that is precisely the same effect as getting the 2 megawatts of additional generation which is then available for somebody else to use.

Q. Well, I don't know why you can't see it the way I do, but to me, it is a lot more attractive to displace load. We will leave --

A. Well, I think Mr. Brown put it that the situation may physically be exactly the same and the only difference is where you place the meters.

Q. I think we will leave this one.

I would like to turn to Volume 67, page 12778 -- no, that must be -- I am sorry.

THE CHAIRMAN: I think it is going to be a later volume.

MR. GREENSPOON: 12778 and I don't seem to have the volume.

MS. PATTERSON: It is Volume 71.

THE CHAIRMAN: 71?

MS. PATTERSON: Yes.

MR. GREENSPOON: Q. Now, this is you, Mr. Vyrostko. It starts at 12777 at the bottom of the page:

"One of my responsibilities is to see if I can get a ratepayer benefit as well. And so the question then is, I am also looking, from the developer, for something for the province, and so the question is: Am I able to get something for the province as well as him getting something for himself?"

And then I think you repeat the same sentiment at page 12780, line 8 -- oh, you haven't found it yet, Mr. Chairman, I am sorry.

THE CHAIRMAN: No, I have got it, thanks.

MR. GREENSPOON: Q. Okay. You repeat the same sentiment at 12780, line 8:

"I said that if the project comes in at $300 million and the developer is asking for the full avoided cost, and our position is that we don't think he needs it, we would be asking him to justify why he needs it."

So my question is: I don't understand

this. I didn't think that this fit in with the mandate of Ontario Hydro and I don't understand why Ontario Hydro doesn't publish whatever the particular avoided cost is for the particular area and pay that price for any project in that area. I can't understand why you don't do that.

MR. VYROSTKO: A. I think, first of all, when we talk about an avoided cost, you can't deal with an avoided cost per area unless you can, in fact, specify the type of project that is going to be in the area.

Q. I meant project when I used the word area.

A. Oh, okay. Then if, in fact, we had a specific project being proposed, and as I explained before through our negotiation process, rather than specifying what the avoided is cost is at the front end, because we don't know all the elements of the project, we can't do that until there is enough in the project established that we can then say, this is what value it has.

Q. But you said in the transcript that if you can get some extra money out of the developer, you are going to try and get it out of him.

And my question is: When a developer can

meet your avoided cost, that should be good enough for the people of Ontario.

A. If, in fact, that is good enough for the people of Ontario, then that is the type of deal we would make.

And right now what we are looking for is we are saying that, if there are projects that can come in below avoided cost, and I believe that that is in the best interest of the province, to try to get projects in that come below avoided cost.

Q. But is that within the mandate of Ontario Hydro, to try and cut profit from a developer when the avoided cost, some people would argue, was already too low?

A. I believe in our Exhibit 74, which is our demand/supply strategy, that we went through a select committee looking at all of our various initiatives to follow through with that demand/supply strategy. And in there it says that we will, if a project is above 5 megawatts, pay up to avoided cost and negotiate that. And so that was discussed and accepted as a principle in the select committee.

Q. Just for the purposes of this next question, just forgetting about avoided cost, do you agree that the cost of new supply, assuming it is

nuclear, is around $3,500 a kilowatt? Is that ballpark - Mr. Snelson, maybe?

MR. SNELSON: A. I would have to check the number.

Q. Well, Darlington is 3,200 megawatts?

A. Yes.

Q. It is about $12 billion. It is around $3,500 a kilowatt?

A. The costs are given in the ONCI report and they are consistent with Darlington costs as they were at the time the ONCI study was done.

Q. Well, am I out of line by hundreds of dollars, thousands of dollars, or can we agree on something just for ...

A. I haven't got a figure right at my fingertips. It is in the order of $2,000 to $3,000 a kilowatt, but it is that order of magnitude. You have to specify what terms, you know, what in-service date you are talking about and so on.

Q. All right. My question is, Mr. Brown, and maybe you have to do this - maybe you can't do this off the top of your head - but I would like to know what kind of a forecast you would come up with if you used the $3,500 a kilowatt for new supply to do your non-utility generation forecast instead of avoided

cost.

MR. BROWN: A. I don't know if you can separate the two.

Q. Well, I said for the purpose of this question, I don't want to consider avoided cost at all.

Ontario Hydro is talking about new supply and I am asking you the question; let's talk apples and apples and let's talk about non-utility generation as new supply.

And on the same playing field as Darlington at $3,500 a kilowatt or 3,000, whatever figure you want to use, what would your forecast be for non-utility generation?

MR. B. CAMPBELL: Just a minute. Mr. Chairman, I don't think and it would be my submission that the assumption in the question is just something that makes the question virtually, if not impossible to answer, certainly meaningless to try and answer.

It is a simple capital cost number. For a unit of capacity, you pay this much and a unit of a different kind of capacity, you pay that much and it takes no account of operational characteristics, fuel charges. It just says, how much does it cost to build it to the point where it is ready to operate and has nothing to do and the assumption is, that is the only

decision that needs to be made?

In my submission, that is so far from any reasonable approach to examining the alternatives that Mr. Brown should not be required to produce a new forecast based on that proposition.

MR. GREENSPOON: Well, it would be my submission, Mr. Chairman, that that goes to the matter of weight, and I don't agree with my friend that it is meaningless.

My submission is, if he wants to talk about fuel charges -- with some of the alternatives, there's no fuel charges. So, I think Hydro's methodology has been established and we all know how they do their costing and how avoided cost comes out. I am submitting this is another means of analysis. I am not proposing he go and spend hours and hours and do this.

THE CHAIRMAN: When you do your costing, Mr. Brown, you put some kind of a cost figure in, I take it, when you are doing your forecasting.

MR. BROWN: I should turn this over to Mr. Snelson. The capital costs are part of our avoided costs and our best estimates of a nuclear supply in the future is in our avoided costs and I use those numbers to do my plan. And I guess what we are talking about

is how is the avoided cost going to change with different --

THE CHAIRMAN: No.

MR. GREENSPOON: No.

THE CHAIRMAN: I think Mr. Greenspoon's, if I understand it correctly, is simpler than that. It is, what would your forecast be based on a cost of a new nuclear unit of the size of Darlington and assume it to be $3,000 or $3,500 or $2,000? I think that is all he wants to know. I don't know whether that is a difficult thing to do or not.

MR. BROWN: Well, for me to determine an answer, I have to essentially know the impact that has on what we already have as the best estimate. So, you can't just throw a number. I have to know what we use and how that impacts on the number I have.

I have a graph in Exhibit 143 that shows those changes in cogeneration with purchase rates.

MR. GREENSPOON: Q. I guess that I don't want to you consider anything you have already got. I am just saying, compare it to new supply.

I mean, isn't it fair to say --

MR. SNELSON: A. There is a way of doing this, Mr. Greenspoon, from the material that is in the evidence. And that is to go to the levelized unit

energy cost or the accounting unit energy cost, which are both representations of the cost of nuclear capacity if you look at the nuclear numbers.

And so if you go to chapter 14 of Exhibit 3, on page 14-29, you will find that the levelized unit energy cost of nuclear on a system expansion basis is 3.1 cents a kilowatthour.

[4:24 p.m.]

If you look at the material that AMPCO filed this afternoon - and they fortuitously did copy this page - they copied the page from the ONCI report with all of the nuclear LUECs on them.

I believe it was page 31 of -- my friend says Exhibit 335. Yes, that's correct, and that shows a range of nuclear LUECs which takes into account capital costs and it takes into account fuel costs and operating costs, which shows that on a levelized energy basis nuclear plant is in the region of three to four cents a kilowatthour, and those figures are consistent with -- reasonably consistent with the figures for Darlington.

The ONCI figures were compared with the Darlington figures that were available at that time, and that will be found in the reports of ONCI, which is I believe Exhibit 44 and 43.

Q. Well, that doesn't answer my question.

A. Those incorporate capital costs of the order you were talking about.

Q. That's right, but they do a lot else as well that we are probably going to -- I would much rather leave until Panel 9. My question --

A. I agree with you that is a Panel 9 question.

Q. My question is very simple, and if you can't answer it then don't answer it. Say you can't answer it.

I am asking you for a non-utility generation projection, a forecast, based on capital cost alone of 3,500 or 3,000 or 2,500, whatever number you want to choose, and that alone - capital cost only, not changing it the way you do in that book, strictly on the number that I gave you, capital cost alone.

MR. BROWN: A. I can't use that number to come up with a new forecast.

Q. I wanted to ask -- Mr. Brown, are you going to be on Panel 8 for the alternatives?

MR. B. CAMPBELL: Not that I know of.

MR. GREENSPOON: It's a good thing the record can't show the tone of that response.

MR. BROWN: I would state -- I am not sure if --

MR. GREENSPOON: You can leave if you want, Mr. Brown.

MR. BROWN: I am not sure if -- yes, I think there will be discussion behind closed doors.

MR. GREENSPOON: Q. I guess I am asking: Who is the forecaster that is going to be -- I understand we have moved "Alternatives"...

MR. BROWN: A. The economics and the environmental considerations of alternative technologies will be in Panel 8, so they will be able to address how much these things -- how much they cost to produce electricity and the environmental impacts of them.

My job is to forecast their contribution in the future.

Q. So does that mean that when we find out what your proposals are for the alternatives that we won't be able to question you on your forecast at that point?

You have forecast basically no alternatives in your non-utility generation forecast; isn't that right?

THE CHAIRMAN: He forecast them based on

certain assumptions, which he has given, and I suppose if in Panel 8 it turns out that those assumptions are not well founded, then that would put the forecast in question.

MR. GREENSPOON: But the problem I am facing today, Mr. Chairman, is I haven't seen the "Alternatives" report, and I don't know what the assumptions are to cross-examine this forecaster on his forecast, which I think -- which I would like to say -- to be able to cross-examine as being inaccurate, that there is a zero figure --

THE CHAIRMAN: In very crude terms, his forecast is that there is no forecast for up to the year 2000 because the alternatives are not economic, and following 2000 there may be some potential and I think he did discuss that in some way.

MR. GREENSPOON: Yes.

THE CHAIRMAN: Now, if the Panel 8 evidence demonstrates that there are economies there, then I suppose we will have to deal with that situation at that particular point, but I don't think we can go much farther--

MR. GREENSPOON: No, I agree.

THE CHAIRMAN: --with this witness because he isn't able to discuss the technology in any

detailed way.

MR. GREENSPOON: All right. Thank you.

Q. There is a reference. The reference is to Exhibit 83. You don't need to turn it up because I am going to go past that, and I haven't...

In the reference, No. 1, which is -- and I am just bringing this to your attention just to know if you know anything about this, Mr. Brown. That's the Rawson reference, and you kindly provided that for me.

In the Rawson reference there is a reference, No. 6, of a paper written by Amir Shalaby whom we have seen at these hearings, and in that reference he talks about wind and he talks about photovoltaic and he talks about biomass, and have you read that? Are you aware -- have you read this paper?

MR. BROWN: A. It's a 1986, I believe, paper, and Mr. Shalaby did, and I am aware of that, yes.

Q. All right. And is it his -- I would say -- I haven't counted the number of words, but it is about a quarter of a page is all he has on wind. It's not even a quarter of a page; about a fifth of a page, a couple of paragraphs.

He concludes that the average speed of wind in Ontario is six metres per second, and the

average speed in California is around nine metres per second, and, therefore, no role is foreseen for wind generation as a bulk system supply option for Ontario.

Now, is that what you based your forecast on?

A. That is one source, although it's outdated. That's also based on industry projections of their costs in California where the winds are more significant than they are here, and it is also based on a Can WEA wind report which I am producing in an undertaking.

Q. Right. I haven't seen that yet. I am anxious to see that.

I think you said in your direct evidence that a 30 megawatt wind project would come in at about seven cents?

A. No, the Can WEA reports had a scenario that if you paid 7-point-something cents you might be able to get 30 megawatts of wind in Ontario.

Q. Okay. Have you or your -- "you" meaning "Ontario Hydro", gone out in the field and measured the wind?

A. We are using the meteorology data that is provided by I believe the MNR that looks at all of Canada.

Q. But an average wind speed of six metres per second, surely there are some places in northern Ontario, maybe even in southern Ontario, that get wind speeds over the year of an average of nine metres per second?

A. I believe a wind is very site specific, and one of the windiest spots in Ontario is a place where we have put a wind turbine already.

Q. But that wasn't my question. There must be a number of sites in Ontario that have wind speeds averaging over the year of nine-plus metres per second if the Ontario average is, as Mr. Shalaby says, six?

A. I am not aware of any.

Q. Have you investigated the possibility of a wind generator in the Hudson Bay lowlands?

A. We are just looking from Ontario Hydro at providing an alternate technology program to promote wind generation in Ontario, and we are very early in our program.

Ontario Hydro has only put up two windmills. One is in Fort Severn and the other one is at Cortwright.

Q. As far as this -- I don't know if I need to do this, Mr. Chairman, on the record that I

would like a copy of that undertaking as well. Is that enough to get me one? That's the Can WEA report.

THE CHAIRMAN: Yes. All right. Just put it on the record. You will make a note of that.

MR. GREENSPOON: Thank you.

MR. B. CAMPBELL: We will make a note of that undertaking, to do it.

MR. GREENSPOON: Q. Now, just the last thing about wind, you agree that the fuel is free?

MR. BROWN: A. Yes.

Q. You hesitated there. All right.

Now, let's just briefly move on to solar. Again, Mr. Shalaby has a small -- and I gather I will be able to ask more specific questions about wind in Panel 8?

MR. B. CAMPBELL: Absolutely.

MR. GREENSPOON: Absolutely.

MR. B. CAMPBELL: I think in fact you may even be able to ask them of Mr. Shalaby.

MR. GREENSPOON: I don't know. I won't comment on that.

Q. Now, solar, Mr. Shalaby estimates - I think, if my memory serves me correct, the same references that I gave you - at about $1,100 a kilowatt, capital cost, by the year 2000, and that was

his '86 report. Presumably, there it is probably even less, and I guess we will find that out in Panel 8.

MR. BROWN: A. Is this photovoltaic or solar thermal?

Q. Just let me look. I think it's photovoltaic.

Photovoltaic. I will quote from the report:

> The standardized costs shown for photovoltaics assumes a cost of $1,100 per kilowatt for the system by the year 2000.

A. I am not aware of the number off hand, but Panel 8 will definitely have a number for you.

Q. In any event, just a question that you can answer. Would you agree that the cost of solar, the cost of photovoltaics is probably going to continue to drop and the cost of nuclear is probably not?

A. I can't comment on the nuclear. I can comment on solar in that I have seen projections reducing its current price from 40 cents per kilowatthour down to 10 to 15 cents by the year 2000.

Q. Just your earlier comment, you can't

comment on the cost of nuclear. Why can't you?

MR. B. CAMPBELL: Well, Mr. Chairman, we have a whole panel coming up on nuclear. Mr. Brown, like many people at Ontario Hydro, is familiar with the technology, but to comment in the sense of giving evidence in these proceedings is -- we have some sense that we are going to have some people come along who will be able to give you definitive answer to questions rather than just a generalized knowledge, and in my submission that's the appropriate way to deal with it.

THE CHAIRMAN: Well, the cost of nuclear hasn't got a great deal to do with the NUG program. So perhaps we can go on.

MR. GREENSPOON: That's fine. It's not important.

Q. Would you consider an individual - and I don't think it has come up at the hearing yet - an individual solar hot water heater, something that seems about to break through into the market, I put to you, as a load displacement NUG?

MR. BROWN: A. No.

Q. Why is that?

A. Because it's not generating electricity.

Q. But it is a load displacement?

A. That's demand management.

Q. So a solar hot water heater is demand management?

A. Yes.

Q. All right. If it was a solar hot water heater that cooled a photovoltaic on a house that was connected to the grid - and I understand that the latest photovoltaic technology uses water because it runs more efficiently if it's cool and it uses the cooling water as domestic hot water source - if that house was connected to the grid that would be a NUG?

A. The parts that were generating electricity would be considered a load displacement NUG.

Q. Right. And does Hydro encourage that kind of non-utility generation?

A. They also qualify for a 10 per cent preference premium.

Q. And Hydro doesn't have any prohibition, I take it, against an individual user putting Hydro back into the grid?

A. We have connection standards that have to be met.

[4:40 p.m.]

Q. Are there any of those in the

province today?

A. Solar, grid-connected solar?

Q. Photovoltaic?

A. Ontario Hydro has an installation at the Cortwright Conservation area and we are looking at other applications.

Q. Are there any private individuals that do it from their home?

A. I am aware of one.

Q. One in the whole province?

A. That's grid-connected.

Q. Do you know where that is, or is that confidential?

A. I don't believe it's confidential. It's in Mississauga.

Q. And to your knowledge, the electricity is reliable, clean electricity? It must meet the standards.

A. There is a lot of work being undertaken throughout North America on the power quality from the inverters of photovoltaics and wind where DC generation is made. That still requires a lot of review.

The photovoltaic installation in Mississauga did have some teething problems in terms of

that inverter and it's been rectified by Ontario Hydro staff.

Q. Okay. You raised the issue of the premium, now it's come up a couple of times, I am going to just jump ahead and then come back because I would like to deal with it now.

Just before, or in connection with that, is it not true that Ontario Hydro does assume some of the risk on behalf of a private cogenerator in its contract or in the agreements that they make with respect to the protection against major changes in the price of gas?

MR. VYROSTKO: A. We can negotiate some of the risk coverage with the proponent on gas.

Q. And how do you do that?

A. By basically assuming part of the risk of price reopeners escalating, while at the same time assuming the benefits coming go back if the price escalator weren't to go as high.

Q. So, would you agree that at least from the developer's point of view, that has a monetary value?

A. Yes, it does.

Q. And he gets the 10 per cent if he is a high-efficiency cogenerator as well?

A. That's correct.

Q. So, really, the cogenerator that gets the monetary value of the gas risk factor, if I can call it that, plus the 10 per cent, gets more than the renewable NUG, either hydraulic, photovoltaic or wind; doesn't he? You are tilting the playing field in favour of the cogenerator.

A. No, because in many cases if we were to assume the risk on the cogenerator, we probably wouldn't be giving full avoided cost.

Q. Well, you might, though.

A. It depends on what benefits we see coming back in that type of a risk benefit sharing.

MR. SNELSON: A. I think Mr. Vyrostko in his earlier evidence pointed out certain aspects of risk that are particular to renewable projects, particularly hydraulic projects, that we do assume for the benefit of the NUG proponent such as the guaranteed payment provisions and in the less than 5 megawatts the front end loading provisions of certain renewable contracts. So, there are different risks in different technologies that may require sharing.

Q. How was that 10 per cent adder figure calculated?

A. I believe that was extensively

discussed in Panel 3. It's a preference for certain options that it considered to be environmentally and socially more desirable, which has the effect of moving the avoided cost towards the upper end of the range of avoided costs, recognizing that avoided cost is uncertain.

Q. When was it done?

A. The premium was instituted in the spring of last year.

Q. And was it Ontario Hydro alone that did it, or was it in consultation with the Ministry of Energy, government?

A. It was principally Ontario Hydro.

Q. Okay. How was it calculated? I am not clear. Why did you choose 10 and not 12?

THE CHAIRMAN: The 10 per cent, that was gone into very, very extensively in Panel 3, why it was 10 per cent and so on.

MR. GREENSPOON: All right. I couldn't resist, I guess.

Q. Now, I want to ask you some specific questions about specific --

THE CHAIRMAN: I am wondering, Mr. Greenspoon, how much longer you are going to be. Are you going to be more than fifteen minutes?

MR. GREENSPOON: Oh, definitely. Do you want to stop now?

THE CHAIRMAN: I would prefer it, if it's all right with you.

MR. GREENSPOON: No, I have no problem. I thought I might be able to do it by five and I am not even close to half.

THE CHAIRMAN: Now, you know tomorrow morning we are starting off with Hydro.

MR. GREENSPOON: I foresee that I will get reached after the break or something maybe.

THE CHAIRMAN: I don't know.

MR. GREENSPOON: I meant the fall break. (laughter)

THE CHAIRMAN: No, it's not going to be that bad.

MR. GREENSPOON: Okay.

THE CHAIRMAN: Tomorrow morning we start with hydraulic and we will have you and then we must have Dofasco.

MR. GREENSPOON: I am not going to be more than what I was today, I wouldn't think.

THE CHAIRMAN: All right. We are adjourned until tomorrow morning at ten.

MR. GREENSPOON: Thank you.

THE REGISTRAR: This hearing will adjourn until ten o'clock tomorrow morning.

---Whereupon the hearing was adjourned at 4:45 p.m., to be resumed on Thursday, October the 10th, 1991, at 10:00 a.m.

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